UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2002

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-7176

El Paso CGP Company

(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**74-1734212** (I.R.S. Employer Identification No.)
El Paso Building **1001 Louisiana Street** **Houston, Texas** (Address of Principal Executive Offices)	**77002** (Zip Code)

Telephone Number: (713) 420-2600

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
8.375% Coastal Trust Preferred Securities issued by Coastal Finance I	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant: None

Indicate the number of shares outstanding at each of the registrant's classes of common stock, as of the latest practicable date.

Common Stock, par value $1 per share. Shares outstanding on March 26, 2003: 1,000

EL PASO CGP COMPANY MEETS THE CONDITIONS OF GENERAL INSTRUCTION I(1)(a) AND (b) TO FORM 10-K AND IS, THEREFORE, FILING THIS REPORT WITH A REDUCED DISCLOSURE FORMAT AS PERMITTED BY SUCH INSTRUCTION.

Documents incorporated by reference: None

EL PASO CGP COMPANY

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* We have not included a response to this item in this document since no response is required pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

Below is a list of terms that are common to our industry and used throughout this document:

/d	= per day	Mgal	= thousand gallons
Bbl	= barrels	MMBbls	= million barrels
BBtu	= billion British thermal units	MMBtu	= million British thermal units
BBtue	= billion British thermal unit equivalents	MMcf	= million cubic feet
Bcf	= billion cubic feet	MMcfe	= million cubic feet of gas equivalents
Bcfe	= billion cubic feet of gas equivalents	MTons	= thousand tons
MBbls	= thousand barrels	MWh	= megawatt hours
Mcf	= thousand cubic feet	Tcfe	= trillion cubic feet of gas equivalents
Mcfe	= thousand cubic feet of gas equivalents		

When we refer to natural gas and oil in "equivalents," we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

When we refer to "us", "we", "our", "ours", or "Coastal", we are describing El Paso CGP Company and/or our subsidiaries.

PART I

ITEM 1. BUSINESS

General

We are a Delaware corporation originally founded in 1955. In January 2001, we became a wholly owned subsidiary of El Paso Corporation (El Paso) through our merger with a wholly owned El Paso subsidiary. On January 30, 2001, we changed our name from The Coastal Corporation to El Paso CGP Company.

Our principal operations include:

- natural gas transportation, gathering, processing and storage;
- natural gas and oil exploration, development and production;
- power generation;
- energy infrastructure facility development and operation;
- petroleum refining; and
- chemicals production.

Segments

Our operations are segregated into four primary business segments: Pipelines, Production, Field Services and Merchant Energy. These segments are strategic business units that provide a variety of energy products and services. We manage each segment separately, and each segment requires different technology and marketing strategies. As future developments in our business occur and as we carry out our ongoing strategy and plans, we will continue to assess the appropriateness of our business segments. For the operating results and identifiable assets by segment, you should see Part II, Item 8, Financial Statements and Supplementary Data, Note 18, which is incorporated herein by reference.

Our Pipelines segment owns or has interests in approximately 19,600 miles of interstate natural gas pipelines in the U.S. and internationally. In the U.S., our systems connect the nation's principal natural gas supply regions to the four largest consuming regions in the U.S.: the Gulf Coast, California, the Northeast and the Midwest. Our U.S. pipeline systems also own or have interests in over 280 Bcf of storage capacity used to provide a variety of services to our customers. Our international pipeline operations include access between our U.S. based systems and Canada.

Our Production segment conducts our natural gas and oil exploration and production activities. Domestically, we lease approximately 1 million net acres in 10 states, including Texas, Utah, and in the Gulf of Mexico. We also have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary and Indonesia. During 2002, daily equivalent natural gas production exceeded 0.8 Bcfe/d, and our reserves at December 31, 2002, were approximately 2.3 Tcfe.

Our Field Services segment conducts our midstream activities. These services include gathering natural gas from approximately 2,900 natural gas wells with approximately 3,800 miles of natural gas gathering and natural gas liquids (NGL) pipelines, and 12 natural gas processing, treating and fractionation facilities located in producing regions of the south Texas, south Louisiana, Mid-Continent and Rocky Mountain regions.

Our Merchant Energy segment consists of two primary divisions: global power and petroleum. We are an owner of electric generating capacity and own or have interests in 19 power plants in 8 countries. We operate three refineries that have the capacity to process approximately 438 MBbls of crude oil per day and produce a variety of petroleum products. We also produce agricultural and industrial chemicals at four facilities in the U.S. On February 5, 2003, El Paso announced its intent to sell our remaining petroleum and chemical assets, except for our Aruba refinery. During 2002 and the first part of 2003, El Paso also completed or announced several asset sales including the sale of our coal mining assets and operations, petroleum assets and interests in power projects.

Pipelines Segment

Our Pipelines segment provides natural gas transmission, storage, gathering and related services in the U.S. and internationally. We conduct our activities primarily through three wholly owned and two partially owned interstate transmission systems along with five underground natural gas storage entities. The tables below detail our wholly owned and partially owned interstate transmission systems:

Wholly Owned Interstate Transmission Systems

Transmission System	Supply and Market Region	As of December 31, 2002			Average Throughput[(1)]		
		Miles of Pipeline	Design Capacity	Storage Capacity	2002	2001	2000
			(MMcf/d)	(Bcf)		(BBtu/d)	
ANR Pipeline (ANR)	Extends from Louisiana, Oklahoma, Texas and the Gulf of Mexico to the midwestern and northeastern regions of the U.S., including the metropolitan areas of Detroit, Chicago and Milwaukee.	10,600	6,450	207	3,691	3,776	3,807
Colorado Interstate Gas (CIG)	Extends from most production areas in the Rocky Mountain region and the Anadarko Basin to the front range of the Rocky Mountains and multiple interconnects with pipeline systems transporting gas to the Midwest, the Southwest, California and the Pacific Northwest.	4,000	3,100	29	1,563	1,448	1,383
Wyoming Interstate (WIC)	Extends from western Wyoming and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	600	1,860	—	1,194	1,017	832

(1) Includes throughput transported on behalf of affiliates.

Partially Owned Interstate Transmission Systems

Transmission System	Supply and Market Region	As of December 31, 2002			Average Throughput[(1)]		
		Ownership Interest	Miles of Pipeline	Design Capacity[(1)]	2002	2001	2000
		(Percent)		(MMcf/d)		(BBtu/d)	
Alliance Pipeline[(2)]	Extends from western Canada to Chicago.	2	2,345	1,537	1,476	1,479	105
Great Lakes Gas Transmission	Extends from the Manitoba-Minnesota border to the Michigan-Ontario border at St. Clair, Michigan.	50	2,115	2,895	2,378	2,224	2,477

(1) Volumes represent the systems' total design capacity and average throughput and are not adjusted for our ownership interest.

(2) The Alliance pipeline project commenced operations in the fourth quarter of 2000. We sold 12.3 percent of our equity interest in the system during the fourth quarter of 2002, and the remaining 2.1 percent equity interest in the first quarter of 2003.

In addition to the storage capacity on our transmission systems, we own or have interests in the following natural gas storage entities:

Underground Natural Gas Storage Entities

Storage Entity	As of December 31, 2002		Location
	Ownership Interest	Storage Capacity[(1)]	
	(Percent)	(Bcf)	
ANR Storage	100	56	Michigan
Blue Lake Gas Storage	75	47	Michigan
Eaton Rapids Gas Storage	50	13	Michigan
Steuben Gas Storage	50	6	New York
Young Gas Storage	48	6	Colorado

(1) Includes a total of 81 Bcf contracted to affiliates. Storage capacity is under long-term contracts and is not adjusted for our ownership interest.

We have a number of transmission system expansion projects that have been approved by the Federal Energy Regulatory Commission (FERC) as follows:

Transmission System	Project	Capacity (MMcf/d)	Description	Anticipated Completion Date
ANR	Westleg Wisconsin Expansion	218	To increase capacity of ANR's existing system by looping the Madison lateral and by enlarging the Beloit lateral through abandonment and replacement.	November 2004
CIG	Valley Line	92	Installation of additional natural gas compression and air blending facilities to expand the deliverability of the Front Range system.	December 2003

Our transportation, storage and related services (transportation services) revenues consist of reservation and usage revenues. In 2002, approximately 92 percent of our transportation services revenues were attributable to a capacity reservation or a demand charge paid by firm customers. These firm customers are obligated to pay a monthly demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts. The remaining 8 percent of our transportation services revenue was attributable to usage charges based largely on the volumes of gas actually transported or stored on our pipeline systems.

Regulatory Environment

Our interstate natural gas transmission systems and storage operations are regulated by the FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each of our pipeline systems and storage facilities operates under FERC-approved tariffs that establish rates, terms and conditions for services to our customers. Generally, the FERC's authority extends to:

- rates and charges for natural gas transportation, storage, terminalling and related services;
- certification and construction of new facilities;
- extension or abandonment of facilities;
- maintenance of accounts and records;
- relationships between pipeline and marketing affiliates;
- terms and conditions of service;
- depreciation and amortization policies;
- acquisition and disposition of facilities; and
- initiation and discontinuation of services.

The fees or rates established under our tariffs are a function of our costs of providing services to our customers, including a return on our invested capital. Consequently, our financial results have historically been relatively stable; however, these results can be subject to volatility due to factors such as weather, changes in natural gas prices and market conditions, regulatory actions, competition and the creditworthiness of our customers.

In Canada, our pipeline activities are regulated by the National Energy Board. Similar to the FERC, the National Energy Board governs tariffs and rates, and the construction and operation of natural gas pipelines in Canada.

Our interstate pipeline systems are also subject to federal, state and local pipeline safety and environmental statutes and regulations. Our systems have ongoing programs designed to keep our facilities in compliance with pipeline safety and environmental requirements. We believe that our systems are in material compliance with the applicable requirements.

A discussion of significant rate and regulatory matters is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 16, and is incorporated herein by reference.

Markets and Competition

The following table details our markets and competition on each of our wholly owned pipeline systems as of December 31, 2002:

Transmission System	Customer Information[1]	Contract Information	Competition
ANR	Approximately 238 firm and interruptible customers Major Customer: We Energies (1,138 BBtu/d)	Approximately 643 firm contracts Contracted capacity: 98% Weighted average remaining contract term of approximately four years Contract terms expire in 2003-2010.	In the Midwest markets, ANR competes with other interstate and intrastate pipeline companies and local distribution companies in the transportation and storage of natural gas. In the Northeast markets, ANR competes with other interstate pipelines serving electric generation and local distribution companies. Also, Wisconsin Gas, which operates under the name We Energies, is a sponsor of Guardian Pipeline, which was placed in service in December 2002. Guardian will serve a portion of We Energies transportation requirements and will compete directly with ANR.
CIG	Approximately 125 firm and interruptible customers Major Customer: Public Service Company of Colorado (1,095 BBtu/d) (462 BBtu/d)	Approximately 170 firm contracts Contracted capacity: 100% Weighted average remaining contract term of approximately seven years Contract term expires in 2007. Contract term expires in 2008-2025.	CIG serves two major markets, the "on-system" market, consisting of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming, and the "off-system" market, consisting of the transportation of Rocky Mountain production from multiple supply basins to interconnections with other pipelines bound for the Midwest, the Southwest, California and the Pacific Northwest. Competition for the on-system market consists of local production from the Denver-Julesburg basin, an intrastate pipeline, and long-haul shippers who elect to sell into this market rather than the off-system market. Competition for the off-system market consists of other interstate pipelines that are directly connected to CIG's supply sources and transport these volumes to markets in the West, Northwest, Southwest and Midwest.
WIC	Approximately 43 firm and interruptible customers Major Customers: Williams Energy Marketing and Trading (340 BBtu/d) Western Gas Resources (272 BBtu/d) Colorado Interstate Gas Company (247 BBtu/d) CMS Field Services (234 BBtu/d)	Approximately 47 firm contracts Contracted capacity: 100% Weighted average remaining contract term of approximately six years Contract terms expire in 2003-2013. Contract terms expire in 2003-2013. Contract terms expire in 2003-2007. Contract terms expire in 2004-2013.	WIC competes with eight interstate pipelines and one intrastate pipeline for its mainline supply. The Overthrust supply basin, which historically supplies the WIC mainline, has been declining and there has been increased competition from the pipelines serving the West and Northwest market areas for this gas supply. To replace these volumes, WIC is pursuing access to new supply sources. Additionally, WIC's one Bcf expandable Medicine Bow lateral is the primary source of transportation for increasing volumes of Powder River Basin supply. Currently there are two other interstate pipelines that transport limited volumes out of this basin. Upon the approval and construction of the new Cheyenne Plains project[2], WIC will have an increased outlet to mid-continent markets.

(1) Includes natural gas producers, marketers, end-users and other natural gas transmission, distribution and electric generation companies.

(2) The Cheyenne Plains project is a new 30-inch diameter pipeline proposed by us to transport natural gas from the Cheyenne hub to the confluence of several pipelines near Greensburg, Kansas. This pipeline is anticipated to be in service in mid-2005 depending on the timing of regulatory approval.

Electric power generation is one of the fastest growing demand sectors of the natural gas market. The potential consequences of proposed and ongoing restructuring and deregulation of the electric power industry are currently unclear. Restructuring and deregulation benefit the natural gas industry by creating more demand for natural gas turbine generated electric power, but this effect is offset, in varying degrees, by increased generation efficiency and more effective use of surplus electric capacity as a result of open market access. In addition, in several regions of the country, new capacity additions have exceeded load growth and transmission capabilities out of those regions. This will result in lower growth in the gas demand in such regions associated with new power generation facilities.

As our pipeline contracts expire, our ability to extend our existing contracts or re-market expiring capacity is dependent on competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or re-negotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory constraints, we attempt to re-contract or re-market our capacity at the maximum rates allowed under our tariffs, although we, at times, discount these rates to remain competitive. The level of discount varies for each of our pipeline systems.

As a result of the rating agencies downgrading the credit rating of several members of the energy sector, including energy trading companies, and placing them on negative credit watch, the creditworthiness of some customers has deteriorated. We have taken actions to mitigate our exposure by requesting these companies provide us with letters of credit or prepayments as permitted by our tariffs. Our tariffs permit us to request additional credit assurance from our shippers equal to the cost of performing transportation services for various periods as specified in each tariff. If these companies experience financial difficulties or file for Chapter 11 bankruptcy protection and our contracts are not assumed by other counterparties, or if the capacity is unavailable for resale, it could have a material adverse effect on our financial position, operating results or cash flows.

Production Segment

Our Production segment is engaged in the exploration for, and the acquisition, development and production of natural gas, oil and natural gas liquids, primarily in North America. Domestically, we have onshore and coal seam operations and properties in 10 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary and Indonesia.

Strategically, Production emphasizes disciplined investment criteria and manages its existing production portfolio to maximize volumes and minimize costs. It employs geophysical technology and seismic data processing to identify economic hydrocarbon reserves. Production's deep drilling capabilities and hydraulic fracturing technology allow it to optimize production with high-rate completions at competitive reserve replacement costs. Production maintains an active drilling program that capitalizes on its land and seismic holdings. It also acquires production properties subject to acceptable investment return criteria.

Natural Gas and Oil Reserves

The table below details Production's proved reserves at December 31, 2002. Information in this table is based on the reserve report dated January 1, 2003, prepared internally by Production and reviewed by Huddleston & Co., Inc. This information is consistent with estimates of reserves filed with other federal agencies except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience. These reserves include 465,783 MMcfe of production delivery commitments under financing arrangements that extend through 2042.

The financing arrangement supported by these reserves matures in 2006. Total proved reserves on the fields with this dedicated production were 919,265 MMcfe.

	Net Proved Reserves[1]		
	Natural Gas (MMcf)	Liquids[2] (MBbls)	Total (MMcfe)
United States			
Producing	694,112	28,648	866,000
Non-Producing	274,700	11,973	346,537
Undeveloped	598,827	25,859	753,980
Total proved	1,567,639	66,480	1,966,517
Canada			
Producing	89,144	4,213	114,422
Non-Producing	14,555	233	15,953
Undeveloped	26,701	1,694	36,865
Total proved	130,400	6,140	167,240
Other Countries[3]			
Producing	—	—	—
Non-Producing	—	—	—
Undeveloped	76,032	12,652	151,944
Total proved	76,032	12,652	151,944
Worldwide			
Producing	783,256	32,861	980,422
Non-Producing	289,255	12,206	362,490
Undeveloped	701,560	40,205	942,789
Total proved	1,774,071	85,272	2,285,701

(1) Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.
(2) Includes oil, condensate and natural gas liquids.
(3) Includes international operations in Brazil, Hungary and Indonesia.

During 2002, as a result of El Paso's efforts to enhance its liquidity position, we sold reserves totaling 1.6 Tcfe to various third parties. The reserves sold were primarily located in Colorado, Texas, Utah and western Canada.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond Production's control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. As a result, estimates of different engineers often vary. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Reserve estimates are often different from the quantities of natural gas and oil that are ultimately recovered. The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from natural gas and oil properties owned by Production declines as reserves are depleted. Except to the extent Production conducts successful exploration and development activities or acquires additional properties containing proved reserves, or both, the proved reserves of Production will decline as reserves are produced. For further discussion of our reserves, see Part II, Item 8, Financial Statements and Supplementary Data, Note 22.

Wells and Acreage

The following table details Production's gross and net interest in developed and undeveloped onshore, offshore, coal seam and international acreage at December 31, 2002. Any acreage in which Production's interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

	Developed		Undeveloped		Total	
	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]
United States						
Onshore	713,948	208,440	656,301	488,684	1,370,249	697,124
Offshore	315,688	210,795	418,926	391,988	734,614	602,783
Coal Seam	27,488	7,449	160	16	27,648	7,465
Total	1,057,124	426,684	1,075,387	880,688	2,132,511	1,307,372
International						
Australia	—	—	1,770,364	677,350	1,770,364	677,350
Bolivia	—	—	154,840	19,355	154,840	19,355
Brazil	—	—	6,757,164	4,690,446	6,757,164	4,690,446
Canada	338,971	174,533	881,353	698,905	1,220,324	873,438
Hungary	—	—	568,100	568,100	568,100	568,100
Indonesia	—	—	1,213,170	378,397	1,213,170	378,397
Total	338,971	174,533	11,344,991	7,032,553	11,683,962	7,207,086
Worldwide Total	1,396,095	601,217	12,420,378	7,913,241	13,816,473	8,514,458

(1) Gross interest reflects the total acreage we participated in, regardless of our ownership interests in the acreage.
(2) Net interest is the aggregate of the fractional working interest that we have in our gross acreage.

The U.S. domestic net developed acreage is concentrated primarily in the Gulf of Mexico (49 percent), Utah (32 percent), and Texas (16 percent). Approximately 34 percent, 29 percent and 19 percent of our total U.S. net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2003, 2004 and 2005. During 2002, we sold approximately 345,180 net developed and 519,752 net undeveloped acres in Colorado, Texas, Utah and western Canada as a result of El Paso's efforts to enhance its liquidity position.

The following table details Production's working interests in onshore, offshore, coal seam and international natural gas and oil wells at December 31, 2002:

	Productive Natural Gas Wells		Productive Oil Wells		Total Productive Wells		Number of Wells Being Drilled	
	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]
United States								
Onshore	706	593	306	230	1,012	823	28	22
Offshore	212	102	34	22	246	124	3	3
Coal Seam	294	65	—	—	294	65	—	—
Total	1,212	760	340	252	1,552	1,012	31	25
International								
Canada	267	170	135	77	402	247	6	5
Other	1	1	—	—	1	1	—	—
Total	268	171	135	77	403	248	6	5
Worldwide Total	1,480	931	475	329	1,955	1,260	37	30

(1) Gross interest reflects the total number of wells we participated in, regardless of our ownership interests in the wells.
(2) Net interest is the aggregate of the fractional working interest that we have in our gross wells.

During 2002, as a result of El Paso's efforts to enhance its liquidity position, we sold approximately 1,680 net wells in Colorado, Texas, Utah, and western Canada.

The following table details Production's exploratory and development wells drilled during the years 2000 through 2002:

	Net Exploratory Wells Drilled			Net Development Wells Drilled		
	2002	2001	2000	2002	2001	2000
United States						
Productive	8	9	10	176	183	224
Dry	4	3	7	5	19	14
Total	12	12	17	181	202	238
Canada						
Productive	18	21	3	5	38	10
Dry	27	35	3	1	3	1
Total	45	56	6	6	41	11
Other Countries[(1)]						
Productive	1	—	—	—	—	—
Dry	1	6	1	—	1	—
Total	2	6	1	—	1	—
Worldwide						
Productive	27	30	13	181	221	234
Dry	32	44	11	6	23	15
Total	59	74	24	187	244	249

(1) Includes international operations in Australia, Brazil, Hungary and Indonesia.

The information above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of natural gas and oil that may ultimately be recovered.

Net Production, Sales Prices, Transportation and Production Costs

The following tables detail Production's net production volumes, average sales prices received, average transportation costs, average production costs and production taxes associated with the sale of natural gas and oil for each of the three years ended December 31:

	2002	2001	2000
Net Production Volumes			
United States			
Natural Gas (Bcf)	247	373	328
Oil, Condensate and Liquids (MMBbls)	7	8	6
Total (Bcfe)	289	422	367
Canada			
Natural Gas (Bcf)	17	13	1
Oil, Condensate and Liquids (MMBbls)	1	1	—
Total (Bcfe)	23	17	1
Worldwide			
Natural Gas (Bcf)	264	386	329
Oil, Condensate and Liquids (MMBbls)	8	9	6
Total (Bcfe)	312	439	368
Natural Gas Average Sales Price (per Mcf)[(1)]			
United States			
Price excluding hedges	$ 3.15	$ 4.23	$ 3.98
Price including hedges	$ 4.22	$ 4.09	$ 2.90
Canada			
Price excluding hedges	$ 2.85	$ 2.86	$ 4.27
Price including hedges	$ 2.84	$ 2.85	$ 4.27

	2002	2001	2000
Worldwide			
Price excluding hedges	$ 3.09	$ 4.18	$ 3.99
Price including hedges	$ 4.14	$ 4.05	$ 2.90

(1) Prices are stated before transportation costs.

	2002	2001	2000
Oil, Condensate, and Liquids Average Sales Price (per Bbl)(1)			
United States			
Price excluding hedges	$20.08	$23.10	$28.49
Price including hedges	$20.12	$23.10	$24.99
Canada			
Price excluding hedges	$21.56	$17.68	$ —
Price including hedges	$21.55	$18.52	$ —
Worldwide			
Price excluding hedges	$20.28	$22.75	$28.49
Price including hedges	$20.31	$22.81	$24.99
Average Transportation Cost (per Mcfe)			
United States			
Natural gas	$ 0.15	$ 0.06	$ 0.07
Oil, condensate, and liquids	$ 0.66	$ 0.68	$ 0.12
Canada			
Natural gas	$ 0.19	$ 0.17	$ 0.17
Oil, condensate, and liquids	$ 0.39	$ 0.26	$ —
Worldwide			
Natural gas	$ 0.16	$ 0.07	$ 0.07
Oil, condensate, and liquids	$ 0.62	$ 0.65	$ 0.12
Average Production Cost and Production Taxes (per Mcfe)(2)			
United States			
Average Production Cost	$ 0.57	$ 0.50	$ 0.45
Average Production Taxes	$ 0.08	$ 0.16	$ 0.12
Canada			
Average Production Cost	$ 0.80	$ 0.74	$ 0.66
Worldwide			
Average Production Cost	$ 0.59	$ 0.51	$ 0.45
Average Production Taxes	$ 0.07	$ 0.16	$ 0.12

(1) Prices are stated before transportation costs.

(2) Production costs include direct lifting costs (labor, repairs and maintenance, materials and supplies) and the administrative costs of field offices, insurance and property and severance taxes.

Acquisition, Development and Exploration Expenditures

The following table details information regarding Production's costs incurred in its development, exploration and acquisition activities for each of the three years ended December 31:

	2002	2001	2000
		(In millions)	
United States			
Acquisition Costs:			
Proved	$ 23	$ 87	$ 127
Unproved	12	33	130
Development Costs	717	1,026	960
Exploration Costs:			
Delay Rentals	4	9	6
Seismic Acquisition and Reprocessing	2	10	51
Drilling	43	91	136
Total	$ 801	$1,256	$1,410
Canada			
Acquisition Costs:			
Proved	$ 6	$ 232	$ 3
Unproved	7	16	6
Development Costs	80	105	69
Exploration Costs:			
Delay Rentals	—	—	—
Seismic Acquisition and Reprocessing	21	10	10
Drilling	49	9	32
Total	$ 163	$ 372	$ 120
Other Countries[1]			
Acquisition Costs:			
Proved	$ —	$ —	$ —
Unproved	10	26	—
Development Costs	3	14	—
Exploration Costs:			
Delay Rentals	—	—	—
Seismic Acquisition and Reprocessing	34	6	18
Drilling	20	61	14
Total	$ 67	$ 107	$ 32
Worldwide			
Acquisition Costs:			
Proved	$ 29	$ 319	$ 130
Unproved	29	75	136
Development Costs	800	1,145	1,029
Exploration Costs:			
Delay Rentals	4	9	6
Seismic Acquisition and Reprocessing	57	26	79
Drilling	112	161	182
Total	$1,031	$1,735	$1,562

(1) Includes international operations in Australia, Brazil, Hungary and Indonesia.

The table below details approximate amounts spent to develop proved undeveloped reserves that were included in our reserve report as of January 1 of each year:

Cost to Develop Proved Undeveloped Reserves	2002	2001	2000
		(In millions)	
United States	$216	$413	$217
Canada	11	17	24
Total	$227	$430	$241

Regulatory and Operating Environment

Production's natural gas and oil activities are regulated at the federal, state and local levels, as well as internationally by the countries around the world in which Production does business. These regulations include, but are not limited to, the drilling and spacing of wells, conservation, forced pooling and protection of correlative rights among interest owners. Production is also subject to governmental safety regulations in the jurisdictions in which it operates.

Production's domestic operations under federal natural gas and oil leases are regulated by the statutes and regulations of the U.S. Department of the Interior that currently impose liability upon lessees for the cost of environmental impacts resulting from their operations. Royalty obligations on all federal leases are regulated by the Minerals Management Service, which has promulgated valuation guidelines for the payment of royalties by producers. Production's international operations are subject to environmental regulations administered by foreign governments, which include political subdivisions and international organizations. These domestic and international laws and regulations relating to the protection of the environment affect Production's natural gas and oil operations through their effect on the construction and operation of facilities, drilling operations, production or the delay or prevention of future offshore lease sales. We believe that our operations are in material compliance with the applicable requirements. In addition, we maintain insurance on behalf of Production for sudden and accidental spills and oil pollution liability.

Production's business has operating risks normally associated with the exploration for and production of natural gas and oil, including blowouts, cratering, pollution and fires, each of which could result in damage to life or property. Offshore operations may encounter usual marine perils, including hurricanes and other adverse weather conditions, governmental regulations and interruption or termination by governmental authorities based on environmental and other considerations. Customary with industry practices, we maintain insurance coverage on behalf of Production with respect to potential losses resulting from these operating hazards.

Markets and Competition

Our Production segment primarily sells its natural gas to third parties through the trading group of El Paso at spot market prices. As a result of El Paso's plan to exit the energy trading business announced in November 2002, our Production segment is currently evaluating how it will sell its production in the future. Alternatives being considered include whether to cancel its agreement with El Paso's trading group and assume responsibility for natural gas sales to third parties or enter into new marketing agreements with third parties engaged in the marketing of natural gas. Production sells its natural gas liquids at market prices under monthly or long-term contracts and its oil production at posted prices, subject to adjustments for gravity and transportation. Production also engages in hedging activities on its natural gas and oil production to stabilize its cash flows and reduce the risk of downward commodity price movements on sales of its production. This is achieved primarily through natural gas and oil swaps. Under our hedging program, we may hedge up to 50 percent of our anticipated production for a rolling 12-month forward period.

The natural gas and oil business is highly competitive in the search for and acquisition of additional reserves and in the sale of natural gas, oil and natural gas liquids. Production's competitors include major and intermediate sized natural gas and oil companies, independent natural gas and oil operations and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price, contract terms and quality of service. Ultimately, our future success in the production business will be dependent on our ability to find or acquire additional reserves at costs that allow us to remain competitive.

Field Services Segment

Our Field Services segment provides customers with wellhead-to-mainline services, including natural gas gathering, products extraction, fractionation, dehydration, purification, compression and transportation of natural gas and NGL. It also provides well-ties and real-time information services, including electronic wellhead gas flow measurement.

Field Services' assets include natural gas gathering and NGL pipelines, treating, processing and fractionation facilities, in the south Texas, south Louisiana, Mid-Continent and Rocky Mountain regions.

In May 2002, we sold our Dragon Trail processing plant and in November 2002, we sold our 14.4 percent interest in the Aux Sable NGL plant. In December 2002, we sold our Natural Buttes and Ouray gas gathering facilities which included 250 miles of natural gas gathering pipelines with approximately 200 MMcf/d of capacity. These assets gathered 146 BBtu/d for the year ended December 31, 2002. Also in December 2002, we sold our 50 percent interest in the Blacks Fork Gas Processing Company which owns the Blacks Fork natural gas processing plant in Wyoming. In January 2003, we sold several of our small gathering systems located in Wyoming, which included 500 miles of natural gas gathering pipelines with a capacity of 325 MMcf/d. These assets gathered 145 BBtu/d for the year ended December 31, 2002. In March 2003, we received approval to sell our remaining assets in the Mid-Continent region. These assets primarily include our Greenwood, Hugoton, Keyes and Mocane natural gas gathering systems, our Sturgis, Mocane and Lakin processing plants and our processing arrangements at three additional processing plants. We expect this sale to close by the end of 2003.

The following tables provide information on Field Services' natural gas gathering and transportation facilities, its processing facilities and the facilities of its equity method investees:

	As of December 31, 2002		Average Throughput		
Gathering & Treating	**Miles of Pipeline**	**Throughput Capacity**	**2002**	**2001**	**2000**
		(MMcfe/d)		(BBtue/d)	
Field Services	3,816	1,141	628	843	874

	As of December 31, 2002	Average Inlet Volume			Average Natural Gas Liquids Sales		
Processing Plants	**Inlet Capacity**	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**
	(MMcfe/d)		(BBtue/d)			(Mgal/d)	
Field Services	2,889	1,754	1,966	1,910	2,139	2,595	2,409

Regulatory Environment

We are subject to the Natural Gas Pipeline Safety Act of 1968, the Hazardous Liquid Pipeline Safety Act and various environmental statutes and regulations. Each of our pipelines has continuing programs designed to keep the facilities in compliance with pipeline safety and environmental requirements, and we believe that these systems are in material compliance with the applicable requirements.

Markets and Competition

Field Services competes with major interstate and intrastate pipeline companies in transporting natural gas and NGL. Field Services also competes with major integrated energy companies, independent natural gas gathering and processing companies, natural gas marketers and oil and natural gas producers in gathering and processing natural gas and NGL. Competition for throughput and natural gas supplies is based on a number or factors, including price, efficiency of facilities, gathering system line pressures, availability of facilities near drilling activity, service and access to favorable downstream markets.

Merchant Energy Segment

Our Merchant Energy segment consists of two primary divisions: global power and petroleum.

Global Power

Our global power division includes the ownership and operation of domestic and international power generation facilities. We own or have interests in 19 power plants in 8 countries. These plants represent 4,378 gross megawatts of generating capacity, 87 percent of which is sold under power purchase or tolling agreements with terms in excess of five years. Of these facilities, 37 percent are natural gas fired and 63 percent are a combination of coal, NGL and other fuels. Internationally, our focus is on building and acquiring energy infrastructure in developed economies, and to a lesser degree in selected emerging markets. Our primary international areas of focus historically have included Asia and Central America.

Detailed below are our generating capacity by power facility for our power plants as of December 31, 2002:

Project	Gross Megawatts[1]	Ownership Interest
		(Percent)
Bastrop Company, LLC	534	50
CDECCA	62	50
Eagle Point Cogeneration Partnership	233	84
EGE Fortuna	300	25
EGE Itabo	513	25
Habibullah Power	136	50
Midland Cogeneration Venture	1,575	44
Nejapa Power	144	87
Saba Power Company	128	93
Other projects	753	various
Total	4,378	

(1) Gross megawatts represent the tested generating capacity of these facilities.

Detailed below are our power generation projects, by region as of December 31, 2002:

Region	Project Status	Number of Facilities	Gross Megawatts[1]	Net Megawatts[2]
United States				
East Coast	Operational	4	429	429
Central	Operational	2	2,109	952
Asia	Operational	6	600	419
Central America	Operational	6	1,190	419
	Under Construction	1	50	11
Total		19	4,378	2,230

(1) Gross megawatts represent the tested generating capacity of these facilities.
(2) Net megawatts represent our net ownership in the facilities.

Petroleum

In February 2003, El Paso announced its intent to sell substantially all of our petroleum business (with the exception of our Aruba refinery) since it is not core to our primary natural gas business.

Our existing petroleum division: (i) owns or has interests in four crude oil refineries and five chemical production facilities; (ii) has petroleum terminalling and related marketing operations; and (iii) has blending and packaging operations that produce and distribute a variety of lubricants and automotive related products. Of the four refineries we own, we operate three of them. The three refineries we operate have a throughput capability of approximately 438 MBbls of crude oil per day to produce a variety of gasolines, diesel fuels, asphalt, industrial fuels and other products. Our chemical facilities have a production capability of 3,800 tons per day and produce various industrial and agricultural products.

In 2002, our refineries operated at 64 percent of their average combined capacity, at 70 percent in 2001 and at 93 percent in 2000. The aggregate sales volumes at our wholly owned refineries were approximately 110 MMBbls in 2002, 131 MMBbls in 2001 and 182 MMBbls in 2000. Of our total refinery sales in 2002, 38 percent was gasoline, 41 percent was middle distillates, such as jet fuel, diesel fuel and home heating oil, and 21 percent was heavy industrial fuels and other products.

The following table presents average daily throughput and storage capacity at our wholly owned refineries at December 31:

		Average Daily Throughput			At December 31, 2002	
Refinery	**Location**	**2002**	**2001**	**2000**	**Daily Capacity**	**Storage Capacity**
				(In MBbls)		
Aruba	Aruba	146	178	229	280	15,320
Eagle Point	Westville, New Jersey	127	118	143	140	8,492
Corpus Christi[(1)]	Corpus Christi, Texas	—	38	99	—	—
Mobile	Mobile, Alabama	9	10	12	18	600
Total		282	344	483	438	24,412

(1) In June 2001, we leased our Corpus Christi refinery to Valero Energy Corporation for 20 years. In February 2003, Valero exercised its option to purchase the plant and related assets. These volumes only reflect those produced prior to our lease of the facilities.

Our chemical plants produce agricultural fertilizers, gasoline additives and other industrial products from facilities in Nevada, Oregon and Wyoming. The following table presents sales volumes from our wholly owned chemical facilities in the U.S. for each of the three years ended December 31:

	2002	**2001**	**2000**
		(MTons)	
Industrial	512	492	547
Agricultural	380	378	389
Gasoline additives	199	173	214
Total	1,091	1,043	1,150

Since January 2003, we have sold the majority of our interests in our Florida petroleum terminals, our tug and barge operations, and all of our interests in the Corpus Christi refinery. We also announced the sale of our leasehold crude business and asphalt operations. We expect to sell the rest of the assets associated with our petroleum business in 2003, with the exception of the Aruba refinery.

Regulatory Environment

Merchant Energy's domestic power generation activities are regulated by the FERC under the Federal Power Act with respect to its rates, terms and conditions of service. In addition, exports of electricity outside of the U.S. must be approved by the Department of Energy. Merchant Energy's cogeneration power production activities are regulated by the FERC under the Public Utility Regulatory Policies Act (PURPA) with respect to rates, procurement and provision of services and operating standards. Its power generation and refining, chemical and petroleum activities are also subject to federal, state and local environmental regulations. We believe that our operations are in material compliance with the applicable requirements.

Merchant Energy's foreign operations are regulated by numerous governmental agencies in the countries in which these projects are located. Many of the countries in which Merchant Energy conducts and will conduct business have recently developed or are developing new regulatory and legal structures to accommodate private and foreign-owned businesses. These regulatory and legal structures and their interpretation and application by administrative agencies are relatively new and sometimes limited. Many detailed rules and procedures are yet to be issued, and we expect that the interpretation of existing rules in these jurisdictions will evolve over time. We believe that our operations are in material compliance with all environmental laws and regulations in the applicable foreign jurisdictions.

Markets and Competition

During 2002, Merchant Energy's activities served over 1,400 suppliers and 2,900 customers around the world. Merchant Energy's businesses operate in a highly competitive environment. Its primary competitors include:

- affiliates of major oil and natural gas producers;
- multi-national energy infrastructure companies;
- large domestic and foreign utility companies;
- affiliates of large local distribution companies;
- affiliates of other interstate and intrastate pipelines;
- independent energy marketers and power producers with varying scopes of operations and financial resources; and
- independent refining and chemical companies.

Merchant Energy competes on the basis of price, operating efficiency, technological advances, experience in the marketplace and counterparty credit. Each market served by Merchant Energy is influenced directly or indirectly by energy market economics.

Many of Merchant Energy's power generation facilities sell power pursuant to long-term agreements with investor-owned utilities in the U.S. The terms of its power purchase agreements for its facilities are such that Merchant Energy's revenues from these facilities are not significantly impacted by competition from other sources of generation. The power generation industry is rapidly evolving and regulatory initiatives have been adopted at the federal and state level aimed at increasing competition in the power generation business. As a result, it is likely that when the power purchase agreements expire, these facilities will be required to compete in a significantly different market in which operating efficiency and other economic factors will determine success. Merchant Energy is likely to face intense competition from generation companies as well as from the wholesale power markets.

Environmental

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 16, and is incorporated herein by reference.

Employees

As of March 26, 2003, we had approximately 3,060 full-time employees, of which 532 are subject to collective bargaining agreements.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1, Business, and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 16, and is incorporated herein by reference.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Item 4, Submission of Matters to a Vote of Security Holders, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

All of our common stock, par value $1 per share, is owned by El Paso and, accordingly, there is no public trading market for our common stock.

ITEM 6. SELECTED FINANCIAL DATA

Item 6, Selected Financial Data, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The information required by this Item is presented in a reduced disclosure format permitted by General Instruction I to Form 10-K. The Notes to Consolidated Financial Statements contain information that is pertinent to the following analysis, including a discussion of our significant accounting policies.

Results of Operations

We use earnings before interest and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as operating income, adjusted for earnings from unconsolidated affiliates and other miscellaneous non-operating items. Items that are not included in this measure are financing costs, including interest and debt expense, income taxes, discontinued operations, extraordinary items and cumulative effect of accounting changes. The following is a reconciliation of our operating results to EBIT and loss from continuing operations for the years ended December 31:

	2002	2001
	(In millions)	
Operating revenues	$ 8,530	$ 8,724
Operating expenses	(8,394)	(8,666)
Operating income	136	58
Earnings from unconsolidated affiliates	104	233
Minority interest in consolidated subsidiaries	(52)	—
Other income	118	190
Other expenses	(37)	(28)
EBIT	269	453
Interest and debt expense	(433)	(447)
Affiliated interest expense, net	(9)	(46)
Returns on preferred interests of consolidated subsidiaries	(35)	(51)
Income taxes	35	(81)
Loss from continuing operations	$ (173)	$ (172)

We believe EBIT is a useful measurement for our investors because it provides information that can be used to evaluate the effectiveness of our businesses and investments from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures such as operating cash flow.

Overview of Results of Operations

Below are our results of operations (as measured by EBIT), by segment for the years ended December 31, 2002 and 2001. These results include the impacts of restructuring and merger-related costs, asset impairments, other charges, and gains (losses) on long-lived assets, which are discussed further in Item 8, Financial Statements and Supplementary Data, Notes 3, 4 and 20. See Item 8, Financial Statements and Supplementary Data, Note 18, for a reconciliation of our operating results to EBIT by segment.

EBIT by Segment	2002	2001
	(In millions)	
Pipelines	$537	$ 292
Production	(456)	791
Field Services	13	71
Merchant Energy	193	(3)
Segment EBIT	287	1,151
Corporate and other	(18)	(698)
Consolidated EBIT from continuing operations	$269	$ 453

Segment Results

Our four segments: Pipelines, Production, Field Services and Merchant Energy are strategic business units that offer a variety of different energy products and services, each requires different technology and marketing strategies. Below is a discussion and analysis of the operating results of each of our business segments. These results include the impact of the restructuring and merger-related costs, asset impairments and other charges discussed above for all years presented.

Pipelines

Our Pipelines segment consists of interstate natural gas transmission, storage, gathering and related services in the U.S. and internationally. Our interstate natural gas transportation systems face varying degrees of competition from other pipelines, as well as from alternate energy sources used to generate electricity, such as hydroelectric power, nuclear, coal and fuel oil.

We are regulated by the FERC, which regulates the rates we can charge our customers. These rates are a function of our costs of providing services to our customers, and include a return on our invested capital. As a result, our financial results have historically been relatively stable; however, they can be subject to volatility due to factors such as weather, changes in natural gas prices and market conditions, regulatory actions, competition and the credit-worthiness of our customers. In addition, our ability to extend our existing customer contracts or re-market expiring contracted capacity is dependent on competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or re-negotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory constraints, we attempt to re-contract or re-market our capacity at the maximum rates allowed under our tariffs, although we, at times, discount these rates to remain competitive. The level of discount varies for each of our pipeline systems.

In November 2002, we sold 12.3 percent of our 14.4 percent equity interest in the Alliance pipeline system, and net proceeds were $141 million. We completed the sale of our remaining equity interest in Alliance during the first quarter of 2003. Income earned on our investment in Alliance for the year ended December 31, 2002 and 2001, was approximately $21 million and $23 million.

Results of operations of the Pipelines segment were as follows for the years ended December 31:

Pipeline Segment Results

	2002	2001
	(In millions, except volume amounts)	
Operating revenues	$ 926	$1,054
Operating expenses	(507)	(859)
Operating income	419	195
Other income	118	97
EBIT	$ 537	$ 292
Throughput volumes (BBtu/d)[1]	7,716	7,443

[1] Throughput volumes exclude those related to pipeline systems sold in connection with Federal Trade Commission orders related to our merger with El Paso including the Empire State and Iroquois pipeline investments. Throughput volumes exclude intrasegment activities.

Operating revenues for the year ended December 31, 2002, were $128 million lower than in 2001. This decrease was due to a $49 million decrease from natural gas sales, gathering and processing activities due to CIG's sale of the Panhandle field and other production properties in July 2002, a $33 million decrease due to reduced natural gas and liquids sales due to lower prices in 2002, and a $28 million decrease in sale of excess natural gas in 2001. Also contributing to the decrease were $22 million lower transportation revenues due to milder weather in 2002, $19 million from lower resales of natural gas purchased from the Dakota gasification facility and $6 million lower 2002 sales of base gas from abandoned storage fields. These decreases were partially offset by higher reservation revenues of $30 million primarily due to system expansion projects placed in service in 2001.

Operating expenses for the year ended December 31, 2002, were $352 million lower than in 2001 primarily as a result of merger-related costs of $192 million incurred in 2001 to relocate our ANR pipeline operations from Detroit, Michigan to Houston, Texas, costs for employee benefits, severance retention, transition charges and other miscellaneous charges. Also contributing to the decrease were $24 million from lower gas costs for our system supply purchases resulting from lower natural gas prices and volumes, $27 million from lower benefit costs and cost efficiencies following our merger with El Paso, $19 million from lower prices on gas purchases from the Dakota gasification facility, $18 million from lower amortization of goodwill due to the implementation of SFAS No. 142 in 2002, a $22 million decrease in operating expenses due to CIG's sale of Panhandle field and other production properties in July 2002, $11 million due to a gain on the sale of pipeline expansion rights in February 2002, and $5 million lower corporate overhead allocations.

Other income for the year ended December 31, 2002, was $21 million higher than in 2001. The increase was due to the resolution of uncertainties associated with the sales of our interests in the Empire State, Iroquois pipeline systems, and our Gulfstream pipeline project in 2001 of $11 million and higher equity earnings in 2002 of $8 million on our Great Lakes Gas Transmission investment. These increases were partially offset by lower equity earnings of $6 million on Empire State and Iroquois pipeline systems due to the sale of our interests in 2001.

Production

The Production segment conducts our natural gas and oil exploration and production activities. Our operating results are driven by a variety of factors including the ability to locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices and operate at the lowest total cost level possible.

Production has historically engaged in hedging activities on its natural gas and oil production to stabilize cash flows and to reduce the risk of downward commodity price movements on its production. This is achieved primarily through natural gas and oil swaps. In the past, our stated goal was to hedge approximately 75 percent of our anticipated current year production, approximately 50 percent of our anticipated succeeding year production and a lesser percentage thereafter. In May 2002, we modified this hedging strategy. Under the modified strategy, we may hedge up to 50 percent of our anticipated production for a rolling 12-month forward period. This modification of our hedging strategy will increase our exposure to changes in commodity prices which could result in significant volatility in our reported results of operations, financial position and cash flows from period to period. As of December 31, 2002, we have hedged approximately 83 million MMBtu's of our anticipated natural gas production for 2003 at a NYMEX Henry Hub price of $4.36 per MMBtu before regional price differentials and transportation costs.

During 2002, we continued an active onshore and offshore development drilling program to capitalize on our land and seismic holdings. This development drilling was done to take advantage of our large inventory of drilling prospects and to develop our proved undeveloped reserve base. We also completed asset dispositions in Colorado, Utah, western Canada and Texas as part of El Paso's liquidity enhancement plan. Primarily due to our asset dispositions, we have a lower reserve base at January 1, 2003 than we did at January 1, 2002. See Item 8, Financial Statements and Supplementary Data, Note 22, for a discussion of our natural gas and oil reserves. Since our depletion rate is determined under the full cost method of accounting, a lower reserve base coupled with additional capital expenditures in the full cost pool will result in a higher depletion rate in future periods. For the first quarter of 2003, we expect our domestic unit of production depletion rate to be approximately $1.87 per Mcfe.

We currently expect to reduce our total capital expenditures from approximately $1.1 billion in 2002 to approximately $600 million in 2003. We continually evaluate our capital expenditure program and this estimate is subject to change based on market conditions. We will continue to pursue strategic acquisitions of production properties and the development of projects subject to acceptable returns.

Below are the operating results and analysis of these results for the years ended December 31:

Production Segment Results	**2002**	**2001**
	(In millions, except volumes and prices)	
Operating Revenues:		
Natural gas	$ 1,091	$ 1,562
Oil, condensate and liquids	162	200
Other	5	21
Total operating revenues	1,258	1,783
Transportation and net product costs	(52)	(56)
Total operating margin	1,206	1,727
Operating expenses[1]	(1,667)	(942)
Operating income (loss)	(461)	785
Other income	5	6
EBIT	$ (456)	$ 791

[1] Includes production costs, depletion, depreciation and amortization, ceiling test charges, merger related costs, gains (losses) on long-lived assets, changes in accounting estimates, corporate overhead, general and administrative expenses and severance and other taxes.

	2002	2001
	(In millions, except volumes and prices)	
Volumes and Prices:		
Natural gas		
Volumes (MMcf)	263,749	385,793
Average realized prices with hedges ($/Mcf)[1]	$ 4.14	$ 4.05
Average realized prices without hedges ($/Mcf)[1]	$ 3.09	$ 4.18
Average transportation costs ($/Mcf)	$ 0.16	$ 0.07
Oil, condensate and liquids		
Volumes (MBbls)	7,981	8,787
Average realized prices with hedges ($/Bbl)[1]	$ 20.31	$ 22.81
Average realized prices without hedges ($/Bbl)[1]	$ 20.28	$ 22.75
Average transportation costs ($/Bbl)	$ 0.62	$ 0.65

(1) Prices are stated before transportation costs.

For the year ended December 31, 2002, operating revenues were $525 million lower than in 2001. A 32 percent decrease in natural gas volumes and a 26 percent decrease in natural gas prices before hedges and transportation costs account for $799 million of the decrease in revenues, offset by a $326 million favorable variance from natural gas hedging activity in 2002 when compared to 2001. The decline in natural gas volumes is primarily attributed to the sale of properties in Colorado, Utah and Texas. A nine percent decrease in oil, condensate and liquids volumes and an 11 percent decrease in their prices before hedges and transportation costs resulted in a $38 million decrease in revenues.

Transportation and net product costs for the year ended December 31, 2002, were $4 million lower than in 2001 primarily due to a lower percentage of gas volumes subject to transportation fees, offset by higher costs incurred to meet minimum payments on pipeline agreements.

Operating expenses for the year ended December 31, 2002, were $725 million higher than in 2001 primarily due to a $702 million loss recognized in December 2002 on the sale of our natural gas and oil properties in Utah. A loss was recognized on this sale because the reserves sold significantly altered the relationship between capitalized costs and proved reserves. Also contributing to the increase in expenses were non-cash full cost ceiling test charges totaling $245 million incurred in 2002 for our Canadian full cost pool and other international properties, primarily in Brazil and Australia, offset by 2001 non-cash full cost ceiling test charges on international properties totaling $115 million. Also contributing to the increase in 2002 expenses were a $4 million charge for a Canadian intangible asset impairment, and a higher corporate overhead allocation of $43 million partially offset by decreased oilfield service costs of $31 million. Partially offsetting the increase in expenses was the unit of production depletion expense which was lower by $9 million with $128 million resulting from lower production volumes in 2002 offset by $119 million due to higher depletion rates in 2002. The higher depletion rate resulted from higher capitalized costs in the full cost pool and a lower reserve base. Further offsetting the increase in expenses were merger related costs of $45 million and asset impairments of $16 million incurred in 2001 related to our combined operations with El Paso and $10 million for write-downs of materials and supplies recognized in 2001 resulting from the reduction in inventory values due to the implementation of consistent operating standards, strategies and plans following the merger with El Paso. For a discussion of merger-related costs, gains and losses on long-lived assets and changes in accounting estimates, see Item 8, Financial Statements and Supplementary Data, Notes 3, 4 and 5. In addition, the increase in expense was offset by $46 million of lower severance and other taxes in 2002. The severance taxes decreased primarily because of lower natural gas volumes and prices, and for credits taken in 2002 for qualified natural gas wells.

Field Services

Our Field Services segment provides a variety of midstream services, including gathering and transportation of natural gas, processing and fractionation of natural gas, NGL and natural gas derivative products, such as butane, ethane and propane.

During 2002, we identified midstream assets to be sold to third parties as part of El Paso's plan to strengthen its capital structure and enhance its liquidity. See Item 8, Financial Statements and Supplementary Data, Note 2 for further discussion of asset sales completed in 2002.

In May 2002, we sold our Dragon Trail processing plant and in November 2002, we sold our 14.4 percent interest in the Aux Sable NGL plant. In December 2002, we sold our Natural Buttes and Ouray gas gathering facilities. Also in December 2002, we sold our 50 percent interest in the Blacks Fork Gas Processing Company which owns the Blacks Fork natural gas processing plant in Wyoming. In January 2003, we sold several of our small gathering systems located in Wyoming. In March 2003, we received approval to sell our assets in the Mid-Continent region. These assets primarily include our Greenwood, Hugoton, Keyes and Mocane natural gas gathering systems, our Sturgis, Mocane and Lakin processing plants and our processing arrangements at three additional processing plants. We expect this sale to close by the end of 2003. After this sale is completed, our remaining assets will consist primarily of processing facilities in the south Texas, south Louisiana and Rocky Mountain regions.

As a result of our asset sales and the resulting decline in our gathering and treating activities, we expect our future EBIT to decrease considerably.

We attempt to balance our earnings from our operating activities through a combination of fixed-fee based and market-based services. A majority of our gathering and transportation operations earn margins from fixed-fee-based services. However, some of our operations earn margins from market-based rates. Revenues from these market-based rate services are the product of the market price, usually related to the monthly natural gas price index and the volume gathered.

Processing and fractionation operations earn a margin based on fixed-fee contracts, percentage-of-proceeds contracts and make-whole contracts. Percentage-of-proceeds contracts allow us to retain a percentage of the product as a fee for processing or fractionation service. Make-whole contracts allow us to retain the extracted liquid products and return to the producer a Btu equivalent amount of natural gas. Under our percentage-of-proceeds contracts and make-whole contracts, we may have more sensitivity to price changes during periods when natural gas and NGL prices are volatile.

Our operating results and an analysis of those results are as follows for years ended December 31:

Field Services Segment Results	2002	2001
	(In millions, except volumes and prices)	
Gathering, treating and processing gross margins	$ 112	$ 155
Operating expenses	(45)	(100)
Operating income	67	55
Other income (expense)	(54)	16
EBIT	$ 13	$ 71
Volumes and prices		
Gathering and treating		
Volumes (BBtu/d)	628	843
Prices ($/MMBtu)	$ 0.13	$ 0.14
Processing		
Volumes (inlet BBtu/d)	1,754	1,966
Prices ($/MMBtu)	$ 0.12	$ 0.14

Total gross margins for the year ended December 31, 2002, were $43 million lower than in 2001. Margins decreased by approximately $37 million primarily due to lower NGL prices in 2002 and natural declines in production in 2002, which unfavorably impacted our volumes and margins in the Rocky Mountain and south Louisiana regions. We also experienced lower margins of approximately $6 million related to the sale of our Dragon Trail processing plant in May 2002.

Operating expenses for the year ended December 31, 2002, were $55 million lower than in 2001. The decrease was due to gains in 2002 on the sales of our Natural Buttes and Ouray natural gas gathering systems and our Dragon Trail processing plant of $26 million and $10 million, a decrease in merger-related costs of $13 million in connection with our 2001 merger with El Paso and a change in our 2001 estimated environmental remediation liabilities of $9 million. Also contributing to the decrease was $14 million of lower operating and maintenance expenses as a result of the sale of our Dragon Trail processing plant and our cost reduction plan in 2002. The decrease in operating expense was partially offset by a $14 million loss associated with our write-down of goodwill related to our SFAS No. 142 goodwill procedures.

Other income for the year ended December 31, 2002, was $70 million lower than in 2001. The decrease was due to the losses on the sale in 2002 of our investment in the Aux Sable NGL plant and our investment in the Blacks Fork natural gas processing plant of $47 million and $3 million. Also contributing to the decrease in other income for 2002 was a $13 million gain on the sale of our investment in Deepwater Holdings in October 2001 and $6 million of lower equity earnings from Deepwater Holdings as a result of the sale of our interest to El Paso Energy Partners, an affiliate, in October 2001.

Merchant Energy

Our Merchant Energy segment consists of two primary divisions: global power and petroleum. Early in 2003, El Paso announced its intent to exit substantially all of our petroleum activities (excluding our Aruba refinery).

Below are Merchant Energy's operating results and an analysis of those results for the years ended December 31:

Merchant Energy Segment Results	Division				Total Merchant Energy Segment
	Global Power	Petroleum	Other Activities	Eliminations	
			(In millions)		
2002					
Gross margin	$ 678	$ 546	$(12)	$(14)	$ 1,198
Operating expenses	(190)	(872)	—	14	(1,048)
Operating income (loss)	488	(326)	(12)	—	150
Other income (expense)	(72)	110	5	—	43
EBIT	$ 416	$ (216)	$ (7)	$ —	$ 193
2001					
Gross margin	$ 38	$ 806	$ 4	$ —	$ 848
Operating expenses	(57)	(1,028)	(26)	—	(1,111)
Operating loss	(19)	(222)	(22)	—	(263)
Other income	141	112	7	—	260
EBIT	$ 122	$ (110)	$(15)	$ —	$ (3)

Global Power

Our global power division includes the ownership and operation of domestic and international power generating facilities. In most cases, we partially own our power generating facilities and account for them using the equity method.

Power Contract Restructuring Activities. Many of our domestic power plants have long-term power sales contracts with regulated utilities that were entered into under the Public Utility Regulatory Policies Act of 1978 (PURPA). The power sold to the utility under these PURPA contracts is required to be delivered from a specified power generation plant at power prices that are usually significantly higher than the cost of power in the wholesale power market. Our cost of generating power at these PURPA power plants is typically higher than the cost we would incur by obtaining the power in the wholesale power market, principally because the PURPA power plants are less efficient than newer power generation facilities.

Typically, in a power contract restructuring, the PURPA power sales contract is amended so that the power sold to the utility does not have to be provided from the specific power plant. Because we have been able to buy lower cost power in the wholesale power market, we have the ability to reduce the cost paid by the utility, thereby inducing the utility to enter into the power contract restructuring transaction. Following a contract restructuring, the power plant operates on a merchant basis, which means that it is no longer dedicated to one buyer and will operate only when power prices are high enough to make its operation economical. In addition, we or our affiliates, may assume, and in the case of our Eagle Point Cogeneration facility, our affiliate, did assume, the business and economic risks of supplying power to the utility to satisfy the delivery requirements under the restructured power contract over its term. When this risk is assumed, its risk is managed by entering into transactions to buy power from third parties over the life of the contract. Power contract restructurings generally result in a higher return in our power generation business because we can deliver reliable power at lower prices than our cost to generate power at these PURPA power plants. In addition, we can use the restructured contracts as collateral to obtain financing at a cost that is comparable to, or lower than, our existing financing costs.

During 2002, we completed restructurings of several long-term power contracts held by our unconsolidated affiliates or, in some cases, held by us. As a result of our credit downgrades, El Paso's decision to exit its trading business and disruption in the capital markets, it is unlikely we will pursue additional power contract restructurings in the near term. For a further discussion of these activities, see Item 8, Financial Statements and Supplementary Data, Note 11.

Global Power Division Results

	2002	2001
	(In millions)	
Gross margin	$ 678	$ 38
Operating expenses	(190)	(57)
Operating income (loss)	488	(19)
Other income (expense)	(72)	141
EBIT	$ 416	$122

Gross margins consist of revenues from our power plants and the net results from our power restructuring activities. The cost of fuel used in the power generation process is included in operating expenses. For the year ended December 31, 2002, gross margin for the global power division was $640 million higher than in 2001. Gross margin from power contract restructurings comprised $486 million of the increase. During 2002, we completed power contract restructurings or contract terminations at our Eagle Point Cogeneration and Nejapa power plants. The Eagle Point restructuring transaction, completed in March 2002, was our most significant power contract restructuring transaction and contributed $359 million to our net 2002 results.

The Eagle Point restructuring involved several steps and all revenues, expenses, fees and impairments related to the transaction were reported in our 2002 gross margin. First, we amended the existing PURPA power sales contract with Public Service Electric and Gas (PSEG) to eliminate the requirement that power be delivered specifically from the Eagle Point power plant. This amended contract has fixed prices with stated increases over the 14-year term that range from $85 per MWh to $126 per MWh. We entered into the amended power sales contract through a consolidated subsidiary, UCF. UCF was created to hold and execute the terms of the restructured power sales contract, to enter into a supply contract to meet the requirements of the restructured agreement and to monetize the net cash flows of these contracts by issuing debt. In keeping with its purpose, UCF entered into a power supply agreement with El Paso's energy trading division (EPME) who usually participates in our power restructuring activities by taking on the obligation to supply power. The terms of the EPME power supply contract were identical to the amended restructured power sales contract, with the exception of price, which was set at $37 per MWh over its 14-year term.

For credit enhancement purposes, in anticipation of the financing transaction associated with the restructuring, UCF terminated the EPME supply contract in the second quarter of 2002 and replaced it with a supply contract with a Morgan Stanley affiliate. UCF entered into the Morgan Stanley contract solely for the purpose of reducing the cost of debt UCF would issue.

The actions taken to restructure the contract required us to mark the contract to its fair value. As a result, we recorded non-cash revenue representing the estimated fair value of the derivative contracts of approximately $898 million. We also amended or terminated other ancillary agreements associated with the cogeneration facility, such as gas supply and transportation agreements, a steam contract and existing financing agreements. We also paid $103 million to the utility to terminate the original PURPA contract. Also included in our operating results for 2002 were a $98 million non-cash charge to adjust the Eagle Point Cogeneration plant to fair value based on its new status as a peaking merchant plant and a non-cash charge of $230 million to write off the book value of the original PURPA contract. The transaction included closing and other costs of $58 million and the minority interest owner's share of this transaction of $50 million. Total operating cash flows from this transaction amounted to approximately $161 million of cash paid to the utility to amend the original contract and other costs and total financing cash flows included $829 million of proceeds from the issuance of 7.944% senior notes collateralized solely by the contracts and cash flows of UCF.

We also employed the principles of our power restructuring business in contract termination at our Nejapa power plant in 2002. In 2002, an arbitration award panel approved the termination of the power purchase agreement between Comision Ejecutiva Hydrolectrica del Rio Lempa and the Nejapa Power Company, one of our consolidated subsidiaries, in exchange for a cash payment of $90 million. We recorded, as gross margin, a $90 million gain and also recorded $13 million in other expense for the minority owner's share of this gain. We applied the proceeds of the award to retire a portion of Nejapa's debt.

Due to increasing market power prices in 2002, the net increase in gross margin of $486 million from our initial power restructuring transactions was partially offset by a decrease in the fair value of our restructured power contract and related power supply contracts of $34 million from the initial gains through December 31, 2002. In addition to the net increase in gross margin relating to restructuring activities discussed above, gross margin increases of $139 million were realized from domestic and international power facilities that were consolidated in the fourth quarter of 2001 and the first quarter of 2002, partially offset by decreased revenues from the sale of the ManChief facility in 2001.

Operating expenses include the cost of fuel used in the power generation processes, asset impairments and other costs we incur in operating and maintaining our power plants. Operating expenses for the year ended December 31, 2002, were $133 million higher than in 2001 primarily as a result of a $79 million increase in plant operation and maintenance expenses and a $16 million increase in depreciation expense, which both resulted from the consolidation of international and domestic power-related entities in the first quarter of 2002. Operating expenses also increased due to a $35 million increase in fuel costs to run the plants as a result of higher fuel prices during 2002. We also wrote down our capitalized turbine costs by $18 million in 2002 as El Paso reduced its capital expenditure plans related to future power developments as a result of El Paso's liquidity concerns, and accordingly our ability and intent to use the turbines in international and domestic power development projects changed.

Other income for the year ended December 31, 2002, was $213 million lower than in 2001 primarily due to a decrease in equity earnings from projects consolidated in the fourth quarter of 2001 and first quarter of 2002 of $52 million. Also contributing to the decrease was $51 million of minority owner's interest in income of projects consolidated by us in 2002 and a $22 million decrease in operating lease income as a result of the consolidation of Nejapa in 2002.

Petroleum

We announced in February 2003 our intent to exit substantially all of our petroleum businesses, except for our Aruba refinery. We currently own or have interests in oil refineries, chemical production facilities, petroleum terminalling and marketing operations, and blending and packaging operations for lubricants and automotive products. Our refinery operations are cyclical in nature and sensitive to movements in the price of crude oil. During the last two years, we have operated in an environment where the differences in the price of our crude oil input and the price we can realize for the resulting products output has been so narrow that we have experienced losses in our refinery operations. While the condition has improved during the first quarter of 2003, our results in the future may continue to be volatile. Also contributing to losses in 2002 and 2001 were operational difficulties following a fire at our Aruba facility in 2001.

Petroleum Division Results

	2002	2001
	(In millions)	
Gross margin	$ 546	$ 806
Operating expenses	(872)	(1,028)
Operating loss	(326)	(222)
Other income	110	112
EBIT	$(216)	$ (110)

Gross margin consists of revenues from our refineries and commodity trading activities, less costs of the feedstocks used in the refining process and the costs of commodities sold. For the year ended December 31, 2002, our gross margin was $260 million lower than in 2001. This decrease was primarily due to lower refining margins of $84 million resulting from lower throughput at our Aruba refinery. Also, we recorded $57 million of insurance claims and recoveries in 2001 related to our refinery losses associated primarily with a fire at our Aruba facility in April 2001, a decrease of $143 million in marine revenues resulting from lower marine freight rates and number of operating vessels and a decrease of $86 million associated with the lease of our Corpus Christi refinery and related assets to Valero in June 2001. These decreases were partially offset by increased refining margins of $74 million at our Eagle Point refinery.

Operating expenses for the year ended in December 31, 2002, were $156 million lower than in 2001. The decrease was primarily due to $244 million of merger-related costs, asset impairments and other charges in 2001 primarily associated with combining our operations with El Paso's operations. This decrease was partially offset by a $91 million impairment of our MTBE chemical processing plant in 2002. See Item 8, Financial Statements and Supplementary Data, Note 3 and 4, for a discussion of our merger-related costs and asset impairments of our long-lived assets.

Other income for the year ended December 31, 2002, was $2 million lower than in 2001. This decrease was primarily due to lower equity earnings of $17 million in 2002 from our Estonia and Subic Bay equity investments. These decreases were partially offset by $46 million of insurance claims and recoveries from our insurers recorded in 2002 compared to $40 million net of writeoffs of damaged properties in 2001, primarily associated with the assets destroyed in a fire at our Aruba facility in April 2001.

Corporate and Other Expenses, Net

Our Corporate and Other operations include our general and administrative activities, as well as other miscellaneous businesses. For the year ended December 31, 2002, Corporate and Other Expenses were $680 million lower than in 2001. The decrease was primarily due to a charge of $520 million in merger-related costs for 2001, in connection with our merger with El Paso. Additional costs for the year ended December 31, 2001 were charges of $144 million related to increased estimates of environmental remediation and reductions in fair value of spare parts inventories to reflect changes in usability of spare parts inventories in our corporate operations based on an ongoing evaluation of our operating standards and plans following the merger.

Interest and Debt Expense

Interest and debt expense for the year ended December 31, 2002, was $14 million lower than in 2001. Below is an analysis of our interest expense during the year ended December 31 (in millions):

	2002	2001
Long term debt, including current maturities	$ 414	$ 390
Commercial paper	—	7
Other interest	37	86
Less: Capitalized interest	(18)	(36)
Total interest expense	$ 433	$ 447

Interest expense on long-term debt for the year ended December 31, 2002, was $24 million higher than in 2001 primarily due to $37 million increase in interest from UCF and Mohawk River Funding IV as a result of our consolidation of these companies in 2002. Proceeds from these borrowings were used for ongoing capital projects, investment programs and operating requirements. Also contributing to the increase was a $9 million increase in interest related to the Valero lease financing loan, issued in the fourth quarter of 2001, that was outstanding for the entire year in 2002. These increases were partially offset by a $26 million decrease due to the retirement of approximately $1 billion of long-term debt with an average interest rate of 5.6%. The remaining increase was primarily due to various debt issuances during 2001 that were outstanding for the entire year in 2002.

Interest expense on commercial paper for the year ended December 31, 2002, was $7 million lower than in 2001. The decrease was due to no amounts outstanding related to short-term credit facilities during 2002.

Other interest for the year ended December 31, 2002, was $49 million lower than in 2001. The decrease was primarily due to a $22 million decrease resulting from the retirement of our other financing obligations, an $18 million decrease in the factoring of receivables, and an $8 million decrease due to the termination of a marketing sales contract during 2002.

Capitalized interest for the year ended December 31, 2002, was $18 million lower than in 2001 primarily due to lower interest rates in 2002 as compared to 2001.

Affiliated Interest Expense

Affiliated interest expense for the year ended December 31, 2002, was $9 million, or $37 million lower than in 2001. The decrease was primarily due to lower short-term interest rates on decreased average advances payable to El Paso under our cash management program. The average short-term interest rates for the year decreased from 4.3% in 2001 to 1.8% in 2002. The average advance payables balance decreased from $1 billion in 2001 to $470 million in 2002.

Minority Interest in Consolidated Subsidiaries

Expense associated with minority interest in consolidated subsidiaries for the year ended December 31, 2002, was $52 million higher than in 2001. This increase was primarily due to 2002 income of $38 million related to the minority interest owners share of income on Eagle Point Cogeneration, Utility Contract Funding, CDECCA and Mohawk River Funding IV. We consolidated these companies during 2002. An additional $13 million of the increase related to the minority owner's share of the gain from the termination of the Nejapa power purchase agreement.

Returns on Preferred Interests of Consolidated Subsidiaries

Returns on preferred interests of consolidated subsidiaries for the year ended December 31, 2002, were $16 million lower than in 2001, primarily due to the redemption of all the preferred interests related to El Paso Oil & Gas Resources, El Paso Oil & Gas Associates and Coastal Limited Ventures. The decrease was also due to lower interest rates in 2002. Most of the preferred returns are based on variable short-term rates, which were lower on average in 2002 than the same periods in 2001.

For a further discussion of our borrowings and other financing activities related to our consolidated subsidiaries, see Item 8, Financial Statements and Supplementary Data, Note 14.

Income Tax Expense

Income tax benefit for the year ended December 31, 2002, was $35 million resulting in an effective tax rate of 17 percent. For the year ended December 31, 2001, income tax expense was $81 million, resulting in an effective tax rate of (89) percent. Of the 2001 amount, $106 million related to non-deductible merger charges and changes in our estimate of additional tax liabilities. The majority of these estimated additional liabilities were paid in 2001 and are being contested by us. The effective tax rate excluding these charges was 28 percent. Differences in our effective tax rates from the statutory tax rate of 35 percent in all years were primarily a result of the following factors:

- state income taxes;
- non-deductible portion of merger-related costs and other tax adjustments to provide for revised estimated liabilities;
- foreign income taxed at different rates;
- non-deductible dividends on the preferred stock of a subsidiary;
- depreciation, depletion and amortization; and
- goodwill impairment.

For a reconciliation of the statutory rate of 35 percent to the effective rates, see Item 8, Financial Statements and Supplementary Data, Note 8.

Liquidity and Capital Resources

Liquidity

We rely on cash generated from our internal operations and loans from our parent company through El Paso's cash management program as our primary sources of liquidity, as well as available credit facilities, bank financings, asset sales and the issuance of long-term debt, preferred securities and equity securities. We expect that our future funding for working capital needs, capital expenditures, long-term debt repayments, dividends and other financing activities will continue to be provided from some or all of these sources. Each of these sources are impacted by factors that influence the overall amount of cash generated by us and the capital available to us. For example, cash generated by our business operations may be impacted by changes in commodity prices or demands for our commodities or services due to weather patterns, competition from other providers or alternative energy sources. Collateral demands or recovery of collateral posted are impacted by natural gas prices, hedging levels and our credit quality and that of our counterparties. Liquidity generated by future asset sales may depend on the overall economic conditions of the industry served by these assets, the condition and location of the assets and the number of interested buyers. In addition, our credit ratings or general market conditions can restrict our ability to access capital markets, which can have a significant impact on our liquidity. See a further discussion of these and other risks that could impact us beginning on page 34.

In a series of credit rating agency actions in late 2002 and early 2003, and contemporaneously with the downgrades of the senior unsecured indebtedness of El Paso, our senior unsecured indebtedness was downgraded to below investment grade and is currently rated Caa1 by Moody's and B by Standard & Poor's. We remain on negative outlook by both agencies. These downgrades will increase our cost of capital and could impede our access to capital markets in the future. These downgrades also resulted in cash generated by several of our consolidated companies that collateralize a minority interest financing arrangement being largely unavailable to us for general corporate purposes. Instead, we are required to use this cash to redeem preferred securities issued in connection with this arrangement and for the operation of those companies. In February 2003, we paid approximately $103 million under this provision. This provision will continue until the amounts outstanding under the financing arrangement have been repaid. As of December 31, 2002, the total amount outstanding on this arrangement was approximately $950 million.

Under El Paso's cash management program, depending on whether we have short-term cash surpluses or requirements, we either provide cash to El Paso or El Paso provides cash to us. As of December 31, 2002 we had borrowed $2.4 billion from El Paso.

In August 2002, the FERC issued a notice of proposed rulemaking requiring, among other things, that FERC regulated entities participating in cash management arrangements with non-FERC regulated parents maintain a minimum proprietary capital balance of 30 percent, and that the FERC regulated entity and its parent maintain investment grade credit ratings as a condition to participating in the cash management program. If this proposal were adopted, the cash management program between El Paso and our FERC-regulated subsidiaries could terminate, which could affect our liquidity. We cannot predict the outcome of this rulemaking at this time.

Our cash flows from continuing operations for the years ended December 31 were as follows:

	Year Ended	
	2002	2001
	(In millions)	
Cash flows from operating activities	$165	$ 1,945
Cash flows from investing activities	(85)	(1,958)
Cash flows from financing activities	(93)	97

As a result of our downgrades, our access to cash from the capital markets has been limited. In order to improve our liquidity position, we have taken steps to reduce our cash needs for 2003, including implementing cost savings plans, exiting marginally performing businesses with high working capital requirements, and reducing our overall capital spending program. In order to supplement our cash generated from operations in 2002, we sold $1.8 billion of assets. We expect to continue to sell assets in 2003 to supplement our liquidity. In March 2003, we generated $400 million of cash from the issuance of debt at our ANR Pipeline subsidiary.

In addition to our sources of cash from internally generated funds, asset sales and capital markets transactions, we also will rely on advances from El Paso through the use of El Paso's cash management program. Our ability to continue to rely on cash advances from our parent can be impacted by our parent company's own credit standing, their requirements to repay debt and other financing obligations, and the cash demands from other parts of its business.

We believe we will generate sufficient funds through our operations, asset sales, financing activities and advances from El Paso to meet all of our cash needs as discussed below.

Capital Expenditures and Investments in Unconsolidated Affiliates

Our capital expenditures and investments in unconsolidated affiliates by segments during the periods indicated are listed below:

	Year Ended December 31, 2002	Year Ended December 31, 2001
	(In millions)	
Pipelines	$ 252	$ 421
Production	1,124	1,814
Field Services	20	53
Merchant Energy	281	142
Other	98	136
Total	$1,775	$2,566

Under our current plan, we expect to spend between approximately $938 million and $1,018 million in each of the next three years for capital expenditures through a combination of internally generated funds and external financing. These capital expenditures will be primarily spent on maintenance and expansion projects.

Debt

The following table shows our total long-term debt as of December 31, 2002:

	2002
	(In millions)
Long-term debt	
El Paso CGP	$3,242
El Paso Power	1,041
El Paso Production Company	200
ANR Pipeline	513
Colorado Interstate Gas	280
Other	84
	5,360
Less:	
Unamortized discount	6
Current maturities	369
Total long-term debt, less current maturities	$4,985

Aggregate maturities of the principal amounts of long-term debt and other financing obligations for the next 5 years and in total thereafter are as follows (in millions):

2003	$ 369
2004	556
2005	364
2006	655
2007	60
Thereafter	3,356
Total long-term debt and other financing obligations including current maturities	$5,360

Credit Facilities

In June 2002, El Paso amended its existing $1 billion 3-year revolving credit and competitive advance facility to permit El Paso to issue up to $500 million in letters of credit and to adjust pricing terms. This facility matures in August 2003. We are a designated borrower under this facility and, as such, are jointly and severally liable for any amounts outstanding under this facility. The interest rate varies based on El Paso's senior unsecured debt rating, and as of December 31, 2002, an initial draw would have had a rate of LIBOR plus 1.00% plus a 0.25% utilization fee. As of December 31, 2002, there were no borrowings outstanding, and $456 million in letters of credit were issued under the $1 billion facility. In February 2003, El Paso borrowed $500 million under the $1 billion facility.

The availability of borrowings under our credit and borrowing agreements is subject to specified conditions, which we currently meet. These conditions include compliance with the financial covenants and ratios required by such agreements, absence of default under such agreements, and continued accuracy of the representations and warranties contained in such agreements. As a result of downgrades in our credit ratings, the current interest rate on an initial draw under both of the facilities would be at a rate of LIBOR plus 1.00%, plus a 0.25% utilization fee for drawn amounts above 25% of the committed amounts.

Restrictive Covenants

We have entered into debt instruments and guaranty agreements that contain covenants such as restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on sales of assets, capitalization requirements, dividend restrictions and cross-acceleration provisions. A breach of any of these covenants could accelerate our debt and other financial obligations and that of our subsidiaries.

One of the most significant debt covenants is that we must maintain a minimum net worth of $1.2 billion. If breached, the amounts guaranteed by the guaranty agreements could be accelerated. The guaranty agreements also have a $30 million of cross-acceleration provision.

In addition, we have indentures associated with our public debt that contain $5 million cross-acceleration provisions.

During 2000, El Paso formed a series of companies that it refers to as Clydesdale. Clydesdale was formed to provide financing to invest in various capital projects and other assets. A third-party investor contributed cash of $1 billion into Clydesdale in exchange for the preferred securities of one of El Paso's consolidated subsidiaries. The financing arrangement is collateralized by a combination of notes payable from us, a production payment from us, various natural gas and oil properties and Colorado Interstate Gas Company. The credit downgrades of El Paso have resulted in the net cash generated by these assets being largely unavailable to us for general corporate purposes. The cash generated by these assets can only be used to redeem the preferred securities issued in connection with these arrangements, and for the operations of the business units associated with this transaction. As of December 31, 2002, the total amount outstanding on the Clydesdale transaction was $950 million.

In a series of rating agency actions in late 2002 and early 2003, and contemporaneously with the downgrades of the senior unsecured indebtedness of El Paso, our senior unsecured indebtedness was downgraded below investment grade and is currently rated Caa1 by Moody's and B by Standard & Poor's. These downgrades will increase our cost of capital and collateral requirements and could impede our access to capital markets in the future.

Guarantees

We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. For example, if the guaranteed party is required to deliver natural gas to a third party and then fails to do so, we would be required to either deliver that natural gas or make payments to the third party equal to the difference between the contract price and the market value of the natural gas.

As of December 31, 2002, we had approximately $50 million of guarantees in connection with our international development and operating activities not consolidated on our balance sheet and approximately $11 million of guarantees in connection with our domestic development and operating activities not consolidated on our balance sheet.

Residual Value Guarantees

Under one of our operating leases, we have provided a residual value guarantee to the lessor. Under this guarantee, we can either choose to purchase the asset at the end of the lease term for a specified amount, which is equal to the outstanding loan amount owed by the lessor, or we can choose to assist in the sale of the leased asset to a third party. Should the asset not be sold for a price that equals or exceeds the amount of the guarantee, we would be obligated for the shortfall. The level of our residual value guarantee is 89.9 percent of the original cost of the leased assets. Accounting for this residual value guarantee will be impacted effective July 1, 2003 by our adoption of the new accounting rules on consolidations. For a discussion of the accounting impact of these new rules, see Note 1.

As of December 31, 2002, we had a purchase option and residual value guarantee associated with the operating lease for the following asset:

Asset Description	Purchase Option	Residual Value Guarantee	Lease Expiration
		(In millions)	
Facility at Aruba refinery	$370	$333	2006

Recent Events

In January 2003, we retired various debt obligations of approximately $47 million. In February 2003, Valero exercised its option to purchase our Corpus Christi refinery and we used the proceeds to repay a $240 million loan that was secured by the refinery lease with Valero.

In February 2003, ANR also distributed to its parent $400 million of intercompany receivables.

In March, 2003, ANR issued $300 million of 8⅞% senior unsecured notes due 2010, raising net proceeds of $288 million. ANR used $263 million of cash proceeds from the offering to reduce existing intercompany payables. ANR retained $25 million of net proceeds from the offering to fund future capital expenditures.

Commitments and Contingencies

For a discussion of our commitments and contingencies, see Item 8, Financial Statements and Supplementary Data, Note 16 and is incorporated herein by reference.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2002, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us. Below is a discussion of the more significant standards that could impact us.

Accounting for Asset Retirement Obligations

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, *Accounting for Asset Retirement Obligations.* This statement requires companies to record a liability for the estimated retirement and removal costs of long-lived assets used in their business. The liability is recorded at its fair value, with a corresponding asset which is depreciated over the remaining useful life of the long-lived asset to which the liability relates. An ongoing expense will also be recognized for changes in the value of the liability as a result of the passage of time. The provisions of SFAS No. 143 are effective for fiscal years beginning after

June 15, 2002. We expect that we will record a charge as a cumulative effect of accounting change of approximately $21 million, net of income taxes, upon our adoption of SFAS No. 143 on January 1, 2003. We also expect to record non-current retirement assets of $106 million and non-current retirement liabilities of $135 million on January 1, 2003. Our liability relates primarily to our obligations to plug abandoned wells in our Production and Pipelines segments over the next four to 24 years.

Accounting for Costs Associated with Exit or Disposal Activities

In July 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* This statement will require us to recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. Examples of costs covered by this guidance include lease termination costs, employee severance costs associated with a restructuring, discontinued operations, plant closings or other exit or disposal activities. The statement is effective for fiscal years beginning after December 31, 2002, and will impact any exit or disposal activities we initiate after January 1, 2003.

Accounting for Guarantees

In November 2002, the FASB issued FIN No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* This interpretation requires that companies record a liability for all guarantees issued after January 31, 2003, including financial, performance and fair value guarantees. This liability is recorded at its fair value upon issuance and does not affect any existing guarantees issued before January 31, 2003. This standard also requires expanded disclosures on all existing guarantees at December 31, 2002. We have included these required disclosures in Item 8, Financial Statements and Supplementary Data, Note 16.

Consolidation of Variable Interest Entities

In January 2003, the FASB issued FIN No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51.* This interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity. This standard requires that companies consolidate a variable interest entity if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. The provisions of FIN No. 46 are effective for all variable interest entities created after January 31, 2003, and are effective on July 1, 2003, for all variable interest entities created before January 31, 2003. We are currently evaluating the effects of this pronouncement, but have reached several tentative conclusions about the possible impact of this interpretation on us. See Item 8, Financial Statements and Supplementary Data, Note 1, for a discussion of the conclusion reached.

RISK FACTORS AND CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and in good faith, assumed facts or bases almost always vary from the actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we or our management express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. The words "believe," "expect," "estimate," "anticipate" and similar expressions will generally identify forward-looking statements. Our forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany those statements. In addition, we disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

With this in mind, you should consider the risks discussed elsewhere in this report and other documents we file with the Commission from time to time and the following important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by us or on our behalf.

Risks Related to Our Business

The success of our pipeline and field services businesses depends on factors beyond our control.

Most of the natural gas and natural gas liquids we transport, gather, process and store are owned by third parties. As a result, the volume of natural gas involved in these activities depends on the actions of those third parties, and is beyond our control. Further, the following factors, most of which are beyond our control, may unfavorably impact our ability to maintain or increase current throughput, to renegotiate existing contracts as they expire, or to remarket unsubscribed capacity:

- future weather conditions, including those that favor alternative energy sources;
- price competition;
- drilling activity and supply availability;
- expiration and/or turn back of significant capacity;
- service area competition;
- changes in regulation and actions of regulatory bodies;
- credit risk of customer base;
- increased cost of capital; and
- natural gas and liquids prices.

The revenues of our pipeline businesses are generated under contracts that must be renegotiated periodically.

Substantially all of our pipeline subsidiaries' revenues are generated under contracts which expire periodically and must be renegotiated and extended or replaced. We cannot assure you that we will be able to extend or replace these contracts when they expire or that the terms of any renegotiated contracts will be as favorable as the existing contracts.

In particular, our ability to extend and/or replace contracts could be adversely affected by factors we cannot control, including:

- the proposed construction by other companies of additional pipeline capacity in markets served by our interstate pipelines;
- changes in state regulation of local distribution companies, which may cause them to negotiate short-term contracts or turn back their capacity when their contracts expire;
- reduced demand and market conditions;
- the availability of alternative energy sources or gas supply points; and
- regulatory actions.

If we are unable to renew, extend or replace these contracts or if we renew them on less favorable terms, we may suffer a material reduction in our revenues and earnings.

Fluctuations in energy commodity prices could adversely affect our business.

Revenues generated by our transmission, storage, gathering and processing contracts depend on volumes and rates, both of which can be affected by the prices of natural gas and natural gas liquids. Increased prices could result in loss of load from our customers, such as power companies not dispatching gas fired power plants, industrial plant shut down or load loss to competitive fuels and local distribution companies' loss of customer base. The success of our transmission, gathering and processing operations is subject to continued development of additional oil and natural gas reserves and our ability to access additional suppliers from interconnecting pipelines to offset the natural decline from existing wells connected to our systems. A decline in energy prices could precipitate a decrease in these development activities and could cause a decrease in the volume of reserves available for transmission, gathering and processing through our systems or facilities. Fluctuations in energy prices are caused by a number of factors, including:

- regional, domestic and international supply and demand;
- availability and adequacy of transportation facilities;
- energy legislation;
- federal and state taxes, if any, on the sale or transportation of natural gas and natural gas liquids;
- abundance of supplies of alternative energy sources; and
- political unrest among oil producing countries.

The agencies that regulate our pipeline businesses and their customers affect our profitability.

Our pipeline businesses are regulated by the FERC, the U.S. Department of Transportation, and various state and local regulatory agencies. Regulatory actions taken by those agencies have the potential to adversely affect our profitability. In particular, the FERC regulates the rates our pipelines are permitted to charge their customers for their services. If our pipelines' tariff rates were reduced in a future rate proceeding, if our pipelines' volume of business under their currently permitted rates was decreased significantly, or if our pipelines were required to substantially discount the rates for their services because of competition, the profitability of our pipeline businesses could be reduced.

Further, state agencies that regulate our pipelines' local distribution company customers could impose requirements that could impact demand for our pipelines' services.

The success of our natural gas and oil exploration and production businesses is dependent on factors that are beyond our control.

The performance of our natural gas and oil exploration and production businesses is dependent upon a number of factors that we cannot control. These factors include:

- fluctuations in natural gas and crude oil prices including basis differentials;
- the results of future drilling activity;
- our ability to identify and precisely locate prospective geologic structures and to drill and successfully complete wells in those structures in a timely manner;
- our ability to expand our leased land positions in desirable areas, which often are subject to intensely competitive leasing conditions;
- increased competition in the search for and acquisition of reserves;
- risks incident to operations of natural gas and oil wells;
- future drilling, production and development costs, including drilling rig rates and oil field services costs;
- future tax policies, rates, and drilling or production incentives by state, federal, or foreign governments;

- increased federal or state regulations, including environmental regulations, that limit or restrict the ability to drill natural gas or oil wells, reduce operational flexibility, or increase capital and operating costs;
- decreased demand for the use of natural gas and oil because of market concerns about global warming or changes in governmental policies and regulations due to climate change initiatives; and
- continued access to sufficient capital to fund drilling programs to develop and replace a reserve base with rapid depletion characteristics.

Estimates of natural gas and oil reserves may change.

Actual production, revenues, taxes, development expenditures, and operating expenses with respect to our reserves will likely vary from our estimates of proved reserves of natural gas and oil, and those variances may be material. The process of estimating natural gas and oil reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, geophysical, engineering, and economic data for each reservoir or deposit. As a result, these estimates are inherently imprecise. Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves may vary substantially from our estimates. In addition, we may be required to revise the reserve information, downward or upward, based on production history, results of future exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control.

The success of our power generation activities depends on many factors beyond our control.

The success of our domestic and international power projects could be adversely affected by factors beyond our control, including:

- alternative sources and supplies of energy becoming available due to new technologies and interest in self generation and cogeneration;
- increases in the costs of generation, including increases in fuel costs;
- uncertain regulatory conditions resulting from the ongoing deregulation of the electric industry in the U.S. and in foreign jurisdictions;
- our ability to negotiate successfully and enter into, restructure or recontract advantageous long-term power purchase agreements;
- the possibility of a reduction in the projected rate of growth in electricity usage as a result of factors such as regional economic conditions, excessive reserve margins and the implementation of conservation programs;
- risks incidental to the operation and maintenance of power generation facilities;
- the inability of customers to pay amounts owed under power purchase agreements; and
- the increasing price volatility due to deregulation and changes in commodity trading practices.

Our objectives in exiting the energy trading business and the petroleum business may not be achieved in the time period or in the manner we expect, if at all.

In November 2002, El Paso announced our intention to exit the energy trading business and pursue an orderly liquidation of our trading portfolio. In February 2003, El Paso announced our intention to sell our remaining petroleum assets, excluding the Aruba refinery. If we are unable to achieve these objectives in the time period or the manner that we expect, it could have a substantial negative impact on our cash flows, liquidity and financial position. The ability to achieve our goals in the liquidation of our trading portfolio is subject to factors beyond our control, including, among others, liquidity constraints experienced by the counterparties in our energy trading business, obtaining maximum cash flow from our trading portfolio and isolating the credit and liquidity needs of the energy trading business from the rest of our business. Additionally, any amounts actually realized from the liquidation of the energy trading business could be significantly less than the amounts we currently expect from such liquidations. Ongoing losses from our trading business are expected to be incurred as positions are liquidated. The ability to achieve our goals in the sale of our petroleum assets is subject to factors beyond our control, including, among others, our ability to locate potential buyers in a timely fashion and obtain a reasonable price, and competing asset sales programs by our competitors.

Our use of derivative financial instruments could result in financial losses.

Some of our subsidiaries use futures, swaps and option contracts traded on the New York Mercantile Exchange, over-the-counter options and price and basis swaps with other natural gas merchants and financial institutions. We could incur financial losses in the future as a result of volatility in the market values of the energy commodities we trade, or if one of our counterparties fails to perform under a contract. The valuation of these financial instruments can involve estimates. Changes in the assumptions underlying these estimates can occur, changing our valuation of these instruments and potentially resulting in financial losses. To the extent we hedge our commodity price exposure and interest rate exposure, we forego the benefits we would otherwise experience if commodity prices were to increase, or interest rates were to change. The use of derivatives also requires the posting of cash collateral with our counterparties which can impact our working capital when commodity prices or interest rates change. For additional information concerning our derivative financial instruments, see Item 7A, Quantitative and Qualitative Disclosures About Market Risk and Item 8, Financial Statements and Supplementary Data, Note 11.

Our foreign operations and investments involve special risks.

Our activities in areas outside the U.S. are subject to the risks inherent in foreign operations, including:

- loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, wars, insurrection and other political risks;
- the effects of currency fluctuations and exchange controls, such as devaluation of foreign currencies and other economic problems; and
- changes in laws, regulations and policies of foreign governments, including those associated with changes in the governing parties.

Costs of environmental liabilities, regulations and litigation could exceed our estimates.

Our operations are subject to various environmental laws and regulations. These laws and regulations obligate us to install and maintain pollution controls and to clean up various sites at which regulated materials may have been disposed of or released. Some of these sites have been designated Superfund sites by the EPA under the Comprehensive Environmental Response, Compensation and Liability Act. We are also party to legal proceedings involving environmental matters pending in various courts and agencies.

It is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental matters because of:

- the uncertainties in estimating clean up costs;
- the discovery of new sites or information;
- the uncertainty in quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the nature of environmental laws and regulations; and
- the possible introduction of future environmental laws and regulations.

Although we believe we have established appropriate reserves for liabilities, including clean up costs, we could be required to set aside additional reserves in the future due to these uncertainties. For additional information concerning our environmental matters, see Item 8, Financial Statements and Supplementary Data, Note 16.

Our operations are subject to operational hazards and uninsured risks.

Our operations are subject to the inherent risks normally associated with those operations, including pipeline ruptures, explosions, pollution, release of toxic substances, fires and adverse weather conditions, and other hazards, each of which could result in damage to or destruction of our facilities or damages to persons and property. In addition, our operations face possible risks associated with acts of aggression on our domestic and foreign assets. If any of these events were to occur, we could suffer substantial losses.

While we maintain insurance against many of these risks, our financial condition and operations could be adversely affected if a significant event occurs that is not fully covered by insurance.

Terrorist attacks aimed at our facilities could adversely affect our business.

On September 11, 2001, the U.S. was the target of terrorist attacks of unprecedented scale. Since the September 11th attacks, the U.S. government has issued warnings that energy assets, including our nation's pipeline infrastructure, may be a future target of terrorist organizations. These developments have subjected our operations to increased risks. Any future terrorist attack on our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business.

We will face competition from third parties to produce, transport, gather, process, fractionate, store or otherwise handle natural gas, oil, natural gas liquids and other petroleum products.

The natural gas and oil business is highly competitive in the search for and acquisition of reserves and in the gathering and marketing of natural gas and oil production. Our competitors include the major oil companies, independent oil and gas concerns, individual producers, gas marketers and major pipeline companies, as well as participants in other industries supplying energy and fuel to industrial, commercial and individual consumers. If we are unable to compete effectively with services offered by other energy enterprises, our future profitability may be negatively impacted.

Risks Related to Our Affiliation with El Paso

El Paso files reports, proxy statements and other information with the SEC under the Securities Exchange Act of 1934, as amended. Each prospective investor should consider this information and the matters disclosed therein in addition to the matters described in this report. Such information is not incorporated by reference herein.

Our relationship with El Paso and its financial condition subjects us to potential risks that are beyond our control.

Due to our relationship with El Paso, adverse developments or announcements concerning El Paso could adversely affect our financial condition, even if we have not suffered any similar development. The outstanding senior unsecured indebtedness of El Paso has been downgraded to below investment grade, currently rated Caa1 by Moody's and B by Standard & Poor's (with a negative outlook at both agencies), which in turn resulted in a similar downgrading of our outstanding senior unsecured indebtedness to Caa1 by Moody's and B by Standard & Poor's (with a negative outlook at both agencies). These downgrades will increase our cost of capital and collateral requirements, and could impede our access to capital markets. As a result of these recent downgrades, El Paso has realized substantial demands on its liquidity, which demands have included:

- application of cash required to be withheld from El Paso's cash management program in order to redeem preferred membership interests at one of El Paso's minority interest financing structures; and
- cash collateral or margin requirements associated with contractual commitments of El Paso subsidiaries.

These downgrades may subject El Paso to additional liquidity demands in the future. These downgrades are a result, at least in part, of the outlook generally for the consolidated businesses of El Paso and its needs for liquidity.

In order to meet its short term liquidity needs, El Paso has embarked on its 2003 Operational and Financial Plan that contemplates drawing all or part of its availability under its existing bank facilities and consummating significant asset sales. In addition, El Paso may take additional steps, such as entering into other financing activities, renegotiating its credit facilities and further reducing capital expenditures, which should provide additional liquidity. There can be no assurance that these actions will be consummated on favorable terms, if at all, or even if consummated, that such actions will be successful in satisfying El Paso's liquidity needs. In the event that El Paso's liquidity needs are not satisfied, El Paso could be forced to seek protection from its creditors in bankruptcy. Such a development could materially adversely affect our financial condition.

Pursuant to El Paso's cash management program, surplus cash is made available to us in exchange for an affiliated payable. In addition, we conduct commercial transactions with some of our affiliates. As of December 31, 2002, we have net payables of approximately $2.4 billion to El Paso and its affiliates. If El Paso is unable to meet its liquidity needs, there can be no assurance that we will be able to access cash under the cash management program. However, we might still be required to satisfy affiliated company payables. For a further discussion of these matters, see Part II, Item 8, Financial Statements and Supplementary Data, Note 20.

We are jointly and severally liable for all outstanding amounts under El Paso's $1 billion, 3-year revolving credit and competitive advance facility.

We are a designated borrower under El Paso's $1 billion, 3-year revolving credit and competitive advance facility. As such, we are jointly and severally liable for any amounts outstanding under this facility. As of March 1, 2003, $956 million (including $456 million in letters of credit) was outstanding under the $1 billion facility. If, for any reason, El Paso does not repay any of the outstanding amounts under this facility, and we are required to repay any such amounts, our financial condition and liquidity could be materially adversely affected.

We could be substantively consolidated with El Paso if El Paso were forced to seek protection from its creditors in bankruptcy.

If El Paso were the subject of voluntary or involuntary bankruptcy proceedings, El Paso and its other subsidiaries and their creditors could attempt to make claims against us, including claims to substantively consolidate our assets and liabilities with those of El Paso and its other subsidiaries. The equitable doctrine of substantive consolidation permits a bankruptcy court to disregard the separateness of related entities and to consolidate and pool the entities' assets and liabilities and treat them as though held and incurred by one entity where the interrelationship between the entities warrants such consolidation. We believe that any effort to substantively consolidate us with El Paso and/or its other subsidiaries would be without merit. However, we cannot assure you that El Paso and/or its other subsidiaries or their respective creditors would not attempt to advance such claims in a bankruptcy proceeding or, if advanced, how a bankruptcy court would resolve the issue. If a bankruptcy court were to substantively consolidate us with El Paso and/or its other subsidiaries, there could be a material adverse effect on our financial condition and liquidity.

Ongoing litigation and investigations regarding El Paso could significantly adversely affect our business.

On March 20, 2003, El Paso entered into an agreement in principle (the Western Energy Settlement) with various public and private claimants, including the states of California, Washington, Oregon, and Nevada, to resolve the principal litigation, claims, and regulatory proceedings against El Paso and its subsidiaries relating to the sale or delivery of natural gas and electricity from September 1996 to the date of the Western Energy Settlement. A more detailed description of the Western Energy Settlement can be found in El Paso's reports filed with the SEC. If El Paso is unable to negotiate definitive settlement agreements, or if the settlement is not approved by the courts or the FERC, the proceedings and litigation will continue.

Since July 2002, twelve purported shareholder class action suits alleging violations of federal securities laws have been filed against El Paso and several of its officers. Eleven of these suits are now consolidated in federal court in Houston before a single judge. The suits generally challenge the accuracy or completeness of press releases and other public statements made during 2001 and 2002. The twelfth shareholder class action lawsuit was filed in federal court in New York City in October 2002 challenging the accuracy or completeness of El Paso's February 27, 2002 prospectus for an equity offering that was completed on June 21, 2002. It has since been dismissed, in light of similar claims being asserted in the consolidated suits in Houston. Four shareholder derivative actions have also been filed. One shareholder derivative lawsuit was filed in federal court in Houston in August 2002. This derivative action generally alleges the same claims as those made in the shareholder class action, has been consolidated with the shareholder class actions pending in Houston and has been stayed. A second shareholder derivative lawsuit was filed in Delaware State Court in October 2002 and generally alleges the same claims as those made in the consolidated shareholder class action lawsuit. A third shareholder derivative suit was filed in state court in Houston in March 2002, and a fourth shareholder derivative suit was filed in state court in Houston in November 2002. These two shareholder derivative suits have not been consolidated with the shareholder action pending in federal court in Houston. The third and fourth shareholder derivative suits both generally allege that manipulation of California gas supply and gas prices exposed El Paso to claims of antitrust conspiracy, FERC penalties and erosion of share value. Another action was filed against El Paso in December 2002, on behalf of participants in El Paso's 401(k) plan. At this time, El Paso's legal exposure related to these lawsuits and claims is not determinable.

If El Paso does not prevail in these cases (or any of the other litigation, administrative or regulatory matters disclosed in El Paso's 2002 Form 10-K to which El Paso is, or may be, a party), and if the remedy adopted in these cases substantially impairs El Paso's financial position, the long-term adverse impact on El Paso's credit rating, liquidity and its ability to raise capital to meet its ongoing and future investing and financing needs could be substantial. Such a negative impact on El Paso could have a material adverse effect on us as well.

The proxy contest initiated by Selim Zilkha to replace El Paso's board of directors could have a material adverse effect on us.

On February 18, 2003, Selim Zilkha, a stockholder of El Paso, announced his intention to initiate a proxy solicitation to replace El Paso's entire board of directors with his own nominees and on March 11, 2003, Mr. Zilkha filed his preliminary proxy statement to that effect with the SEC. This proxy contest may be highly disruptive and may negatively impact El Paso's ability to achieve the stated objectives of its 2003 Operational and Financial Plan. In addition, El Paso may have difficulty attracting and retaining key personnel until such proxy contest is resolved. Therefore, this proxy contest, whether or not successful, could have a material adverse effect on El Paso's liquidity and financial condition, which, in turn, could adversely affect our liquidity and financial position.

Results of investigations into reporting of trading information could adversely affect our business.

In response to an October 2002 data request from the FERC, El Paso conducted an investigation into the accuracy of information that employees of El Paso Merchant Energy, an El Paso subsidiary, voluntarily reported to trade publications. As a part of that investigation, El Paso discovered that inaccurate information was submitted to the trade publications. One of El Paso Merchant Energy's former employees has been arrested and charged with knowingly submitting inaccurate data to a trade publication. El Paso has continued its policy of cooperation with the office of the U.S. Attorney and the FERC and intends to take whatever remedial steps are necessary to ensure that its operations are conducted with integrity. However, these investigations are continuing, and there can be no assurance that penalties or sanctions will not be imposed on El Paso, which, in turn, could adversely affect our business.

We are a wholly owned subsidiary of El Paso.

El Paso has substantial control over:

- our payment of dividends;
- decisions on our financings and our capital raising activities;
- mergers or other business combinations;
- our acquisitions or dispositions of assets; and
- our participation in El Paso's cash management program.

El Paso may exercise such control in its interests and not necessarily in the interests of us or the holders of our long-term debt.

Risks Related to Our Long-Term Debt

Our substantial long-term debt could impair our financial condition and our ability to fulfill our debt obligations.

We have substantial long-term debt. As of December 31, 2002, we had total long-term debt of approximately $5.4 billion.

Our substantial long-term debt could have important consequences. For example, it could:

- make it more difficult for us to satisfy our obligations with respect to our long-term debt, which could in turn result in an event of default on any or all of such long-term debt;
- impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate purposes or other purposes;
- diminish our ability to withstand a downturn in our business or the economy generally;
- require us to dedicate a substantial portion of our cash flow from operations to debt service payments, thereby reducing the availability of cash for working capital, capital expenditures, acquisitions, general corporate purposes or other purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage compared to our competitors that have proportionately less debt.

If we are unable to meet our debt service obligations, we could be forced to restructure or refinance our long-term debt, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

Covenants applicable to our long-term debt allow us to incur significant amounts of additional indebtedness. Our incurrence of significant additional indebtedness would exacerbate the negative consequences mentioned above, and could adversely affect our ability to repay our long-term debt.

A breach of the covenants applicable to our long-term debt and other financial obligations could accelerate our long-term debt and other financial obligations and that of our subsidiaries.

Our long-term debt and other financial obligations contain restrictive covenants and cross-acceleration provisions. A breach of any of these covenants could accelerate our long-term debt and other financial obligations and that of our subsidiaries. If this were to occur, we may not be able to repay such long-term debt and other financing obligations upon such acceleration.

Our long-term debt is effectively subordinated to liabilities and indebtedness of our subsidiaries and subordinated to any of our secured indebtedness to the extent of the assets securing such indebtedness.

Holders of any secured indebtedness that have claims with respect to our assets constituting collateral for such indebtedness that are prior to the claims of the holders of our long-term debt. In the event of a default on such secured indebtedness or our bankruptcy, liquidation or reorganization, those assets would be available to satisfy obligations with respect to the indebtedness secured thereby before any payment could be made on our long-term debt. Accordingly, any such secured indebtedness would effectively be senior to our long-term debt to the extent of the value of the collateral securing the indebtedness. While the indentures governing our long-term debt place limitations on our ability to create liens, there are significant exceptions to these limitations, including with respect to sale and leaseback transactions, that will allow us to secure some kinds of indebtedness without equally and ratably securing our long-term debt. To the extent the value of the collateral is not sufficient to satisfy the secured indebtedness, the holders of that indebtedness would be entitled to share with the holders of our long-term debt and the holders of other claims against us with respect to our other assets.

In addition, our long-term debt is not guaranteed by our subsidiaries and our subsidiaries are not prohibited under our indentures from incurring additional indebtedness. As a result, holders of our long-term debt will be effectively subordinated to claims of third party creditors, including holders of indebtedness, of these subsidiaries. Claims of those other creditors, including trade creditors, secured creditors, governmental authorities, and holders of indebtedness or guarantees issued by the subsidiaries, will generally have priority as to the assets of the subsidiaries over claims by the holders of our long-term debt. As a result, rights of payment of holders of our indebtedness, including the holders of our long-term debt, will be effectively subordinated to all those claims of creditors of our subsidiaries.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We use derivative financial instruments and energy related contracts to manage market risks associated with energy commodities and interest rates. Our primary market risk exposures are those related to changing commodity prices. Our market risks are monitored by a corporate risk management committee to ensure compliance with El Paso's stated risk management policies approved by the Audit Committee of El Paso's Board of Directors. This committee operates independently from the business segments that create or manage these risks.

Commodity Price Risk

Our segments are exposed to a variety of market risks in the normal course of their business activities. Our Production segment has market risks related to natural gas and oil it produces. Our Field Services segment has market risks related to the natural gas and natural gas liquids it retains in its processing operations. The refining activities in our Merchant Energy segment are exposed to market risks in both the feedstocks they use, primarily crude oil and petroleum based products as well as the refined products they sell. Our power contract restructuring activities in Merchant Energy segment are exposed to market risks in both the fuel the power plants use as well as the power sold under the restructured contracts. We attempt to mitigate market risk associated with these significant physical transactions through the use of non-trading financial instruments, including:

- exchange-traded futures contracts involving cash settlements;
- forward contracts involving cash settlements or physical delivery of an energy commodity;
- swap contracts which require payment to (or receipts from) counterparties based on the difference between a fixed and a variable price, or two variable prices, for a commodity; and
- exchange-traded and over-the-counter options.

We measure the risk associated with our commodity contracts held for non-trading purposes on a daily basis using a Value-at-Risk model. This model allows us to determine the maximum expected one-day unfavorable impact on the fair value of those contracts due to normal market movement, and monitors our risk in comparison to established thresholds. This technique uses historical price movements and specific, defined mathematical parameters to estimate the characteristics of and the relationships between components of our assets and liabilities held for price risk management activities. Based on a confidence level of 95 percent and a one-day holding period, our estimated potential one-day unfavorable impact on earnings before interest and income taxes was $7 million and $8 million at December 31, 2002 and 2001. The highest and lowest month-end values of our Value-at-Risk were $11 million and $2 million for 2002, and the average of all of our month-end values of our Value-at-Risk was $7 million for 2002.

Interest Rate Risk

Many of our debt-related financial instruments and project financing arrangements are sensitive to changes in interest rates. The table below shows the maturity of the carrying amounts and related weighted average interest rates of our interest-bearing securities, by expected maturity dates and the fair values of those securities. As of December 31, 2002, the carrying amounts of short-term borrowings are representative of fair values because of the short-term maturity of these instruments. The fair value of the long-term securities has been estimated based on quoted market prices for the same or similar issues.

	December 31, 2002								December 31, 2001	
	Expected Fiscal Year of Maturity of Carrying Amounts								Carrying Amounts	Fair Value
	2003	2004	2005	2006	2007	Thereafter	Total	Fair Value		
	(Dollars in millions)									
Liabilities:										
Long-term debt, including current portion — fixed rate	$ 158	$301	$252	$543	$ 52	$3,342	$4,648	$3,931	$4,365	$4,425
Average interest rate	9.1%	7.2%	9.5%	7.2%	7.9%	7.8%				
Long-term debt, including current portion — variable rate	$ 212	$252	$111	$111	$ 7	$ 13	$ 706	$ 706	$2,052	$2,052
Average interest rate	2.5%	4.4%	2.9%	2.7%	2.7%	7.2%				
Preferred interests of consolidated subsidiaries:										
Coastal Finance I						$ 300	$ 300	$ 160	$ 300	$ 299
Average fixed interest rate						8.4%				

The fair value of our long-term securities was significantly impacted by a series of ratings actions initiated by Moody's and Standards & Poor's that lowered our unsecured debt rating to Caa1 and B (both "below investment grade" ratings), and we remain on negative outlook. These rating actions decreased the fair value of all of our fixed rate long-term securities during 2002.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EL PASO CGP COMPANY

CONSOLIDATED STATEMENTS OF INCOME
(In millions)

	Year Ended December 31,		
	2002	2001	2000
Operating revenues			
Pipelines	$ 896	$ 984	$ 972
Production	1,163	1,818	811
Field Services	407	826	711
Merchant Energy	6,064	4,741	11,931
Other	—	355	1,191
	8,530	8,724	15,616
Operating expenses			
Cost of products and services	5,221	5,074	12,309
Operation and maintenance	1,351	1,631	1,462
Restructuring and merger-related costs	5	814	13
(Gain) loss on long-lived assets	791	175	(5)
Ceiling test charges	245	115	—
Depreciation, depletion and amortization	681	698	642
Taxes, other than income taxes	100	159	122
	8,394	8,666	14,543
Operating income	136	58	1,073
Earnings from unconsolidated affiliates	104	233	281
Minority interest in consolidated subsidiaries	(52)	—	—
Other income	118	190	126
Other expenses	(37)	(28)	(10)
Interest and debt expense	(433)	(447)	(502)
Affiliated interest expense, net	(9)	(46)	—
Returns on preferred interests of consolidated subsidiaries	(35)	(51)	(60)
Income (loss) before income taxes	(208)	(91)	908
Income taxes	(35)	81	253
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	(173)	(172)	655
Discontinued operations, net of income taxes	(124)	(5)	(1)
Extraordinary items, net of income taxes	—	(11)	—
Cumulative effect of accounting changes, net of income taxes	14	—	—
Net income (loss)	$ (283)	$ (188)	$ 654

See accompanying notes.

EL PASO CGP COMPANY

CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2002	December 31, 2001
ASSETS		
Current assets		
Cash and cash equivalents	$ 128	$ 141
Accounts and notes receivable		
Customer, net of allowance of $37 in 2002 and $36 in 2001	1,537	1,793
Affiliates	545	569
Other	200	181
Inventory	697	683
Assets from price risk management activities	122	425
Other	432	279
Total current assets	3,661	4,071
Property, plant and equipment, at cost		
Natural gas and oil properties, at full cost	7,479	7,765
Pipelines	6,522	6,556
Refining, crude oil and chemical facilities	2,560	2,524
Power facilities	460	272
Gathering and processing systems	279	428
Other	89	96
	17,389	17,641
Less accumulated depreciation, depletion and amortization	7,259	5,812
Total property, plant and equipment, net	10,130	11,829
Other assets		
Investments in unconsolidated affiliates	1,544	1,882
Assets from price risk management activities	956	267
Intangible assets, net	498	518
Other	444	499
	3,442	3,166
Total assets	$17,233	$19,066

See accompanying notes.

EL PASO CGP COMPANY

CONSOLIDATED BALANCE SHEETS — (Continued)
(In millions, except share amounts)

	December 31, 2002	December 31, 2001
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 1,326	$ 1,832
Affiliates	87	1,336
Other	296	359
Short-term borrowings (including current maturities of long-term debt and other financing obligations)	369	1,410
Liabilities from price risk management activities	248	213
Notes payable to affiliates	2,374	—
Income taxes payable	13	198
Other	448	432
Total current liabilities	5,161	5,780
Debt		
Long-term debt	4,985	5,107
Other liabilities		
Liabilities from price risk management activities	26	1
Deferred income taxes	1,753	1,735
Other	355	579
	2,134	2,315
Commitments and contingencies		
Securities of subsidiaries		
Preferred interests of consolidated subsidiaries	400	750
Minority interests in consolidated subsidiaries	253	144
	653	894
Stockholder's equity		
Common stock, par value $1 per share; authorized and issued 1,000 shares	—	—
Additional paid-in capital	1,339	1,305
Retained earnings	3,102	3,385
Accumulated other comprehensive income (loss)	(141)	280
Total stockholder's equity	4,300	4,970
Total liabilities and stockholder's equity	$17,233	$19,066

See accompanying notes.

EL PASO CGP COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2002	2001	2000
Cash flows from operating activities			
Net income (loss)	$ (283)	$ (188)	$ 654
Less net loss from discontinued operations, net of income taxes	(124)	(5)	(1)
Net income (loss) from continuing operations	(159)	(183)	655
Adjustments to reconcile net income (loss) to net cash from operating activities			
Depreciation, depletion and amortization	681	698	642
Ceiling test charges	245	115	—
Undistributed (earnings) loss from unconsolidated affiliates	43	(106)	(19)
Deferred income tax expense (benefit)	11	(24)	203
(Gains) Losses on long-lived assets	791	175	(5)
Extraordinary items	—	11	—
Cumulative effect of accounting changes	(14)	—	—
Non-cash gains from trading and power restructuring activities	(422)	—	—
Non-cash portion of merger-related costs and changes in estimates	—	1,007	—
Other non-cash income items	—	27	(9)
Working capital changes, net of non-cash transactions			
Accounts and notes receivable	(157)	(599)	(470)
Accounts payable	(940)	557	184
Inventory	43	405	(138)
Changes in trading price risk management activities	(86)	67	(29)
Other working capital changes			
Assets	90	(344)	119
Liabilities	10	(35)	(52)
Non-working capital changes			
Assets	127	541	(55)
Liabilities	(98)	(367)	108
Cash provided by continuing operations	165	1,945	1,134
Cash provided by discontinued operations	90	7	5
Net cash provided by operating activities	255	1,952	1,139
Cash flows from investing activities			
Additions to property, plant and equipment	(1,705)	(2,245)	(2,043)
Equity investments	(45)	(133)	(286)
Net proceeds from the sale of assets	1,650	268	59
Net proceeds from the sale of investments	179	363	59
Net change in restricted cash	(43)	—	—
Repayment of notes receivable from unconsolidated affiliates	(102)	20	—
Net cash (paid) received for acquisitions, net of cash acquired	45	(232)	—
Other	(64)	1	(1)
Cash used in continuing operations	(85)	(1,958)	(2,212)
Cash used in discontinued operations	(12)	(56)	(69)
Net cash used in investing activities	(97)	(2,014)	(2,281)
Cash flows from financing activities			
Net proceeds (repayments) under commercial paper and short-term credit facilities	(30)	(765)	217
Issuances of common stock	—	2	31
Net proceeds from the issuance of long-term debt and other financing obligations	882	490	1,722
Payments to retire long-term debt and other financing obligations	(1,791)	(608)	(738)
Payments to minority interest holders	(160)	—	—
Payments to preferred interest holders	(350)	—	—
Dividends paid	—	(13)	(54)
Net proceeds from issuance of minority interests in subsidiaries	33	139	—
Net change in notes payable to unconsolidated affiliates	(56)	—	—
Net change in affiliated advances payable	1,317	889	—
Contributions from (distributions to) discontinued operations	68	(43)	(65)
Other	(6)	6	—
Cash provided by (used in) continuing operations	(93)	97	1,113
Cash provided by (used in) discontinued operations	(68)	43	65
Net cash provided by (used in) financing activities	(161)	140	1,178
Change in cash and cash equivalents	(3)	78	36
Less change in cash and cash equivalents related to discontinued operations	10	(6)	1
Change in cash and cash equivalents from continuing operations	(13)	84	35
Cash and cash equivalents			
Beginning of period	141	57	22
End of period	$ 128	$ 141	$ 57

See accompanying notes.

EL PASO CGP COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDER'S EQUITY
(In thousands of shares and millions of dollars, except per share amounts)

	Year Ended December 31,					
	2002		2001		2000	
	Shares	Amount	Shares	Amount	Shares	Amount
Preferred stock, par value 33⅓¢ per share, authorized 50,000 shares cumulative convertible preferred						
$1.19, Series A: Beginning balance	—	$ —	52	$ —	53	$ —
Converted to common stock					(1)	—
Converted to El Paso common stock			(52)	—		
Ending balance	—	—	—	—	52	—
$1.83, Series B: Beginning balance	—	—	51	—	58	—
Converted to common stock					(7)	—
Converted to El Paso common stock			(51)			
Ending balance	—	—	—	—	51	—
$5.00, Series C: Beginning balance	—	—	26	—	27	—
Converted to common stock					(1)	—
Converted to El Paso common stock			(26)	—		
Ending balance	—	—	—	—	26	—
Class A common stock, par value 33⅓¢ per share, authorized 2,700 shares						
Beginning balance	—	—	311	—	345	—
Converted to common stock					(35)	—
Conversion of preferred stock and exercise of stock options					1	—
Converted to El Paso common stock			(311)	—		
Ending balance	—	—	—	—	311	—
Common stock, par value 33⅓¢ per share, authorized 500,000 shares						
Beginning balance	1	—	219,605	73	217,705	72
Exercise of stock options			86	—	1,793	1
Conversion to El Paso common stock			(219,690)	(73)		
Other					107	—
Ending balance	1	—	1	—	219,605	73
Additional paid-in capital						
Beginning balance		1,305		1,044		1,032
Merger-related equity exchange				(59)		
Capital contribution from El Paso		32		278		
Tax reallocation		2		36		
Other				6		12
Ending balance		1,339		1,305		1,044
Retained earnings						
Beginning balance		3,385		3,573		2,973
Net income (loss) for period		(283)		(188)		654
Dividends on common stock, 25¢ per share in 2000						(54)
Ending balance		3,102		3,385		3,573
Accumulated other comprehensive income (loss)						
Beginning balance		280		(8)		(8)
Other comprehensive income (loss)		(421)		288		—
Ending balance		(141)		280		(8)
Treasury stock, at cost						
Beginning balance	—	—	(4,395)	(132)	(4,396)	(132)
Retirement of treasury shares			4,395	132		
Other					1	—
Ending balance	—	—	—	—	(4,395)	(132)
Total		$4,300		$4,970		$4,550

See accompanying notes.

EL PASO CGP COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2002	2001	2000
Net income (loss)	$(283)	$(188)	$654
Foreign currency translation adjustments	(12)	(30)	—
Pension minimum liability accrual (net of income tax of $7)	(12)	—	—
Unrealized net gains (losses) from cash flow hedging activities			
Cumulative-effect transition adjustment (net of income tax of $248)	—	(459)	—
Unrealized mark-to-market gains (losses) arising during period (net of income tax of $140 in 2002 and $398 in 2001)	(241)	727	—
Reclassification adjustments for changes in initial value to settlement date (net of income tax of $86 in 2002 and $26 in 2001)	(156)	50	—
Other comprehensive income (loss)	(421)	288	—
Comprehensive income (loss)	$(704)	$ 100	$654

See accompanying notes.

1. Summary of Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications did not impact our reported net income or stockholder's equity.

Principles of Consolidation

We consolidate entities when we have the ability to control the operating and financial decisions and policies of that entity. Where we can exert significant influence over, but do not control, those policies and decisions, we apply the equity method of accounting. We use the cost method of accounting where we are unable to exert significant influence over the entity. The determination of our ability to control or exert significant influence over an entity involves the use of judgment of the extent of our control or influence and that of the other equity owners or participants of the entity. Discussed below as part of new accounting principles issued but not yet adopted is a standard that, once effective, will impact our consolidation principles.

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues and expenses and our disclosures in these financial statements. Actual results can, and often do, differ from those estimates.

Accounting for Regulated Operations

Our natural gas pipelines are subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and Natural Gas Policy Act of 1978. We discontinued the application of regulatory accounting principles under Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* in 1996. SFAS No. 71 provides that rate regulated enterprises account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if those rates are designed to recover the costs of providing the regulated service and if it is reasonable to assume that those rates can be charged and collected. While our rates are designed to recover our costs, our ability to extend or re-market expiring contracts is highly dependent on competitive alternatives at the time these contracts are extended or expire. Currently, a substantial portion of our revenues are under contracts that are discounted at rates below the maximum rates. We will continue to evaluate the application of regulatory accounting principles based on on-going changes in the regulatory and economic environment and further actions in current and future rate cases or settlements.

Cash and Cash Equivalents

We consider short-term investments with an original maturity of less than three months to be cash equivalents.

We maintain cash on deposit with banks and insurance companies that is pledged for a particular use or restricted to support a potential liability. We classify these balances as other current or non-current assets in our balance sheet based on when we expect this cash to be used. As of December 31, 2002, we reported $28 million and $32 million as other current assets and other non-current current assets. As of December 31, 2001, we reported $17 million as a current asset.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable and for natural gas imbalances due from shippers and operators if we determine that we will not collect all or part of the outstanding balance. We regularly review collectibility and establish or adjust our allowance as necessary using the specific identification method.

Inventory

Our inventory consists of refined products, crude oil and chemicals, materials and supplies, natural gas in storage and coal. We also hold power turbines in inventory. We classify inventory as current or non-current based on whether it will be sold or used in the next twelve months. We report non-current inventory as part of other non-current assets in our balance sheets. We use the first-in, first-out and the average cost methods to account for our refined products, crude oil and chemicals inventories and the average cost method to account for our other inventories. We value all inventory at the lower of its cost or market value.

Natural Gas and Oil Imbalances and Exchanges

Natural gas and oil imbalances occur when the actual amount of natural gas or oil delivered from or received by a pipeline system, processing plant or storage facility differs from the contractual amount scheduled to be delivered or received. Natural gas exchange transactions involve receiving or delivering natural gas that will be made up in-kind. We value these imbalances and exchanges due to or from shippers and operators at an appropriate market index price. Imbalances and exchanges are settled in cash or made up in-kind, subject to the contractual terms of settlement and tariffs.

Imbalances and exchanges due from others are reported in our balance sheet as either accounts receivable from customers or accounts receivable from unconsolidated affiliates. Imbalances and exchanges owed to others are reported on the balance sheet as either trade accounts payable or accounts payable to unconsolidated affiliates. In addition, all imbalances and exchanges are classified as current or long-term depending on when we expect to settle them.

Property, Plant and Equipment

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at either the fair value of the assets acquired or the cost to the entity that first placed the asset in service. We capitalize direct costs, such as labor and materials, and indirect costs, such as overhead and interest. We capitalize the major units of property replacements or improvements and expense minor items.

The following table presents our property, plant and equipment by type, depreciation method, remaining useful lives and depreciation rate:

Type	Method	Remaining Useful Lives	Rates
		(In years)	
Pipeline and storage systems	Straight-line	2-60	1% to 25%
Refining, crude oil and chemical facilities	Straight-line	1-33	3% to 20%
Power facilities	Straight-line	5-19	5% to 33%
Gathering and processing systems	Straight-line	1-40	3% to 25%
Transportation equipment	Straight-line	1-5	10% to 33%
Buildings and improvements	Straight-line	1-43	2% to 50%
Office and miscellaneous equipment	Straight-line	1-7	3% to 33%

When we retire facilities, we reduce property, plant and equipment for its original cost, less accumulated depreciation, and salvage value. Any remaining gain or loss is recorded in income.

We capitalize a carrying cost on funds invested in our construction of long-lived assets. This carrying cost includes an interest cost on the investment financed by debt (capitalized interest). The capitalized interest is calculated based on our average cost of debt. Amounts capitalized during the years ended December 31, 2002, 2001 and 2000, were $18 million, $36 million and $55 million. These amounts are included as a reduction of interest expense in our income statements. Capitalized carrying costs for debt is reflected as an increase in the cost of the asset on the balance sheet.

Asset Impairments

We apply the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* to account for asset impairments. Under this standard, we evaluate an asset for impairment when events or circumstances indicate that a long-lived asset's carrying value may not be recovered. These events include market declines, changes in the manner in which we intend to use an asset or decisions to sell an asset and adverse changes in the legal or business environment such as adverse actions by regulators. When we decide to exit or sell a long-lived asset or group of assets, we adjust the carrying value of these assets downward, if necessary, to the estimated sales price, less costs to sell. We also reclassify the asset or assets as either held for sale or as discontinued operations, depending on whether they have independently determinable cash flows.

Natural Gas and Oil Properties

We use the full cost method to account for our natural gas and oil properties. Under the full cost method, substantially all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of natural gas and oil reserves are capitalized. These capitalized amounts include the costs of all unproved properties, internal costs directly related to acquisition, development and exploration activities and capitalized interest.

We amortize these costs using the unit of production method over the life of our proved reserves. Each quarter, we calculate the unit of production depletion rate based on our estimated production and an estimate of proved reserves. Capitalized costs associated with unproved properties are excluded from amortizable costs until these properties are evaluated. Future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values, are included in costs subject to amortization.

Our capitalized costs, net of related income tax effects, are limited to a ceiling based on the present value of future net revenues using end of period spot prices, discounted at 10 percent plus the lower of cost or fair market value of unproved properties, net of related income tax effects. If these discounted revenues are not equal to or greater than total capitalized costs, we are required to write-down our capitalized costs to this level. We perform this ceiling test calculation each quarter. Any required write-downs are included in our income statements as a ceiling test charge. Our ceiling test calculations include the effects of derivative instruments we have designated as cash flow hedges of our anticipated future natural gas and oil production.

We do not recognize a gain or loss on sales of our natural gas and oil properties, unless those sales would significantly alter the relationship between capitalized costs and proved reserves. We treat sales proceeds on non-significant sales as an adjustment to the cost of our properties.

Planned Major Maintenance

Repair and maintenance costs are generally expensed as incurred, unless they improve the operating efficiency or extend the useful life of an asset.

In our domestic refining business, repair and maintenance costs for planned major maintenance activities are accrued as a liability in a systematic and rational manner over the period of time until the planned major maintenance activities occur. Any difference between the accrued liability and the actual costs incurred in performing the maintenance activities are charged or credited to expense at the time the maintenance occurs. At our international refineries, the cost of each major maintenance activity is capitalized and amortized to expense in a systematic and rational manner over the estimated period extending to the next planned major maintenance activity. The types of costs we accrue in conjunction with major maintenance at our refineries are outside contractor costs, materials and supplies, company labor and other outside services. For our domestic operations, we had accruals for major maintenance of $40 million and $36 million at December 31, 2002 and 2001, and for our international operations, we capitalized $75 million and $51 million for the years ended December 31, 2002 and 2001.

Goodwill and Other Intangible Assets

Our intangible assets consist of goodwill resulting from acquisitions and other intangible assets. We apply SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets* to account for these intangibles. Under these standards, we recognize goodwill separately from other intangible assets. In addition, goodwill is not amortized and is periodically tested for impairment, at least annually, or whenever an event occurs that indicates that an impairment may have occurred. We adopted these standards on January 1, 2002 and stopped amortizing goodwill.

SFAS No. 142 requires that we perform impairment tests upon adoption of the standard on January 1, 2002 and at least annually thereafter. The initial impairment tests we performed as of January 1, 2002 indicated no impairment of goodwill. The impairment tests we performed as of December 31, 2002, however, indicated a pre-tax impairment of goodwill associated with our Field Services segment of $14 million. This impairment was recorded in 2002 and was primarily the result of the sale of assets in the Field Services segment during 2002 and early 2003. The net carrying amounts of our goodwill as of January 1, 2002 and December 31, 2002 reported in net intangible assets in our balance sheets, and the changes in the net carrying amounts of goodwill for the year ended December 31, 2002 for each of our segments are as follows:

	Pipelines	Production	Field Services	Merchant Energy	Total
			(In millions)		
Balances as of January 1, 2002	$413	$61	$ 15	$—	$ 489
Impairments	—	—	(14)	—	(14)
Other changes	—	1	—	—	1
Balances as of December 31, 2002	$413	$62	$ 1	$—	$ 476

Our other intangible assets consist of customer lists and other miscellaneous intangible assets. We amortize all intangible assets on a straight-line basis over their estimated useful life. The following are the gross carrying amounts and accumulated amortization of our other intangible assets as of December 31:

	2002	2001
	(In millions)	
Intangible assets subject to amortization	$ 34	$ 34
Accumulated amortization	(12)	(5)
	$ 22	$ 29

Amortization expense of our intangible assets that were subject to amortization was $7 million for the year ended December 31, 2002. For the year ended December 31, 2001, amortization of all intangible assets, including goodwill, was $32 million. Based on the current amount of intangible assets subject to amortization, our estimated amortization expense is approximately $2 million for each of the next five years. These amounts may vary as a result of future acquisitions, dispositions and any recorded impairments.

The following table presents our income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes and net income (loss) for the years ended December 31, 2001 and

2000, as if goodwill had not been amortized during those periods, compared with those amounts reported for the years ended December 31, 2002:

	Year Ended December 31,		
	2002	2001	2000
		(In millions)	
Reported income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$(173)	$(172)	$655
Amortization of goodwill and indefinite-lived intangibles	—	16	15
Adjusted income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$(173)	$(156)	$670
Net income (loss):			
Reported net income (loss)	$(283)	$(188)	$654
Amortization of goodwill and indefinite-lived intangibles	—	16	15
Adjusted net income (loss)	$(283)	$(172)	$669

Pension and Other Postretirement Benefits

El Paso maintains several pension and other postretirement benefit plans. These plans require us to make contributions to fund the benefits to be paid out under the plans. These contributions are invested until the benefits are paid out to plan participants. We record benefit expense in our income statement. This benefit expense is a function of many factors including benefits earned during the year by plan participants (which is a function of the employee's salary, the level of benefits provided under the plan, actuarial assumptions, and the passage of time), expected return on plan assets and recognition of certain deferred gains and losses as well as plan amendments.

We compare the benefits earned, or the accumulated benefit obligation, to the plan's fair value of assets on an annual basis. To the extent the plan's accumulated benefit obligation exceeds the fair value of plan assets, we record a minimum pension liability in our balance sheet equal to the difference in these two amounts. We do not adjust this minimum liability if it is less than the liability already accrued for the plan. If this difference is greater than the pension liability recorded on our balance sheet, however, we record an additional liability and an amount to other comprehensive loss, net of income taxes, on our financial statements.

Revenue Recognition

Our business segments provide a number of services and sell a variety of products. Our revenue recognition policies by segment are as follows:

Pipelines revenues. Our Pipelines segment derives revenues primarily from transportation and storage services and sales under gas sales contracts. For our transportation and storage services, we recognize reservation revenue on firm contracted capacity ratably over the contract period. For interruptible or volumetric based services, we record revenues when we complete the delivery of natural gas to the agreed upon delivery point and when natural gas is injected or withdrawn from the storage facility. Revenues under natural gas sales contracts are recognized when physical deliveries of commodities are made at the agreed upon delivery point. Revenues in all services are generally based on the thermal quantity of gas delivered or subscribed at a price specified in the contract or tariff. We are subject to FERC regulations and, as a result, revenues we collect may possibly be refunded in a final order of a pending or future rate proceeding or as a result of a rate settlement. We have established reserves for these potential refunds.

Production revenues. Our Production segment's revenues are derived principally through physical sales of natural gas, oil and natural gas liquids produced. Revenues from sales of these products are recorded upon the passage of title using the sales method, net of any royalty interests or other profit interests in the produced product. When actual natural gas sales volumes exceed our entitled share of sales volumes, an overproduced imbalance occurs. To the extent the overproduced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, we record a liability. Costs associated with the transportation and delivery of our production are included in cost of sales.

Field Services revenues. Our Field Services segment derives revenues principally from gathering, transportation and processing services and through the sale of commodities that are retained from providing these services. There are two general types of service: fee-based and make-whole. For fee-based services we recognize revenues at the time service is rendered based upon the volume of gas gathered, treated or processed at the contracted fee. For make-whole services, our fee consists of retainage of natural gas liquids and other by-products that are a result of processing, and we recognize revenues on these services at the time we sell these products, which generally coincides with when we provide the service.

Merchant Energy revenues. Merchant Energy derives revenues from a number of sources including physical sales of natural gas, power and petroleum, and petroleum products. Revenues on these physical sales are recognized based on the volumes delivered and the contracted or market price and are recognized at the time the commodity is delivered to the specified delivery point. Revenues from commodities sold as part of Merchant Energy's energy trading division are reflected net of the cost of these sales. The energy trading division of Merchant Energy also enters into derivative transactions which are recorded at their fair value. See a discussion of our income recognition policies on derivatives below under *Price Risk Management Activities.*

Corporate. During 2000 and 2001 our corporate segment owned retail gas stations. These were sold during 2001. We recognized revenues from these activities when products and services were delivered to our retail customers.

Environmental Costs and Other Contingencies

We record liabilities when our environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. We recognize a current period expense for the liability when clean-up efforts do not benefit future periods. We capitalize costs that benefit more than one accounting period, except in instances where separate agreements or legal or regulatory guidelines dictate otherwise. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the EPA or other organizations. These estimates are subject to revision in future periods based on actual costs or new circumstances and are included in our balance sheet in other current and long-term liabilities at their undiscounted amounts. We evaluate recoveries from insurance coverage or government sponsored programs separately from our liability and, when recovery is assured, we record and report an asset separately from the associated liability in our financial statements.

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Funds spent to remedy these contingencies are charged against a reserve, if one exists, or expensed. When a range of probable loss can be estimated, we accrue the most likely amount or at least the minimum of the range of probable loss.

Price Risk Management Activities

We engage in price risk management activities to manage market risks associated with commodities we purchase and sell, interest rates and foreign currency exchange rates. These price risk management activities include trading activities that we enter into with the objective of generating profits or from exposure to shifts or changes in market prices, non-trading activities related to our power investment, generation and power contract restructuring activities, and other non-trading activities that involve hedging the market price risk exposures on our assets, liabilities, contractual commitments and forecasted transactions of each of our business segments. Our trading and non-trading price risk management activities involve the use of a variety of derivative financial instruments, including:

- exchange-traded fixtures contracts that involve cash settlements;
- forward contracts that involve cash settlements or physical delivery of a commodity;
- swap contracts that require payments to (or receipts from) counterparties based on the difference between a fixed and a variable price, or two variable prices, for a commodity; and
- exchange-traded and over-the-counter options.

We account for our trading and non-trading derivative instruments under SFAS No. 133, *Accounting for Derivatives and Hedging Activities.* Under SFAS No. 133, all derivatives are reflected in our balance sheet at their fair value as price risk management activities. We classify our price risk management activities as either current or non-current assets or liabilities based on our overall position by counterparty and their anticipated settlement date. Cash inflows and outflows associated with the settlement of our price risk management activities are recognized in operating cash flows, and any receivables and payables resulting from these settlements are reported separately from price risk management activities in our balance sheet as trade receivables and payables. The accounting for revenues and expenses associated with our price risk management activities varies based on whether those activities are trading activities or non-trading activities. See Note 11 for a further description of our price risk management activities.

During 2002, we adopted DIG Issue No. C-16, *Scope Exceptions: Applying the Normal Purchases and Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract*. DIG Issue No. C-16 requires that if a fixed-price fuel supply contract allows the buyer to purchase, at their option, additional quantities at a fixed-price, the contract is a derivative that must be recorded at its fair value. One of our unconsolidated affiliates, the Midland Cogeneration Venture Limited Partnership, recognized a gain on one fuel supply contract upon adoption of these new rules, and we recorded a gain of $14 million, net of income taxes, as a cumulative effect of an accounting change in our income statement for our proportionate share of this gain.

During 2002, we also adopted the provisions of EITF Issue 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* EITF Issue 02-3 requires that all revenues and costs associated with trading activities should be shown net in the income statement, whether or not they are physically settled. We began to report our trading activity on a net basis (revenues net of the expenses of the physically settled purchases) as a component of revenues effective July 1, 2002. We applied this guidance to all prior periods, which had no impact on previously reported net income or stockholder's equity. Revenues and costs for periods prior to the adoption of EITF Issue No. 02-3 are revised as follows:

	Year Ended December 31,	
	2001	**2000**
	(In millions)	
Gross operating revenues	$ 25,369	$ 26,660
Costs reclassified	(16,645)	(11,044)
Net operating revenues reported in the income statements	$ 8,724	$ 15,616

Income Taxes

We report current income taxes based on our taxable income and we provide for deferred income taxes to reflect estimated future tax payments or receipts. Deferred taxes represent the tax impacts of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. We account for tax credits under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. We reduce deferred tax assets by a valuation allowance when, based on our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates utilized in recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances.

El Paso maintains a tax accrual policy to record both regular and alternative minimum tax for companies included in its consolidated federal income tax return. The policy provides, among other things, that (i) each company in a taxable income position will accrue a current expense equivalent to its federal income tax, and (ii) each company in a tax loss position will accrue a benefit to the extent its deductions, including general business credits, can be utilized in the consolidated return. El Paso pays all federal income taxes directly to the IRS and, under a separate tax billing agreement, El Paso may bill or refund its subsidiaries for their portion of these income tax payments. Prior to the 2001 tax return, we filed a separate tax return and were not subject to El Paso's tax accrual policy.

Excise Taxes

In our refining and marketing operations, we do not record the amounts of excise taxes we bill and collect from customers in revenues. Rather, we record a receivable from our customers and a payable to the government agencies or suppliers.

In our retail business, we sold substantially all of our retail gas stations in 2001. During 2001 and 2000, we accounted for excise taxes by recording amounts billed to customers in operating revenues with a corresponding entry for amounts owed in operating expenses. As of December 31, 2001 and 2000, we recorded approximately $69 million and $198 million in excise taxes related to our retail activities.

Foreign Currency Transactions and Translation

We record all currency transaction gains and losses in income. These gains or losses are classified in our income statement based upon the nature of the transaction that gives rise to the currency gain or loss. For sales and purchases of commodities or goods, these gains or losses are included in operating revenue or expense. For gains and losses arising through equity investees, we record these gains or losses as equity earnings. For gains or losses on foreign denominated debt, we include these gains or losses as a component of interest expense. The net currency loss recorded in operating income was insignificant in 2002 and 2001. The U.S. dollar is the functional currency for the majority of our foreign operations. For foreign operations whose functional currency is deemed to be other than the U.S. dollar, assets and liabilities are translated at year-end exchange rates and included as a separate component of comprehensive income and stockholders' equity. The cumulative currency translation loss recorded in accumulated other comprehensive income was $50 million and $38 million at December 31, 2002 and 2001. Revenues and expenses are translated at average exchange rates prevailing during the year.

Accounting for Debt Extinguishments

We apply the provisions of SFAS No. 145, *Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections* to account for debt extinguishments. Under SFAS No. 145, we are required to evaluate any gains or losses incurred when we retire debt early to determine whether they are extraordinary in nature or whether they should be included as ordinary income from continuing operations in the income statement. In the third quarter of 2002, we retired debt totaling $10 million, which resulted in a gain of $1 million. Because we believe that we will continue to retire debt in the near term, we reported this gain as income from continuing operations, as part of other income.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2002, there were a number of accounting standards and interpretations that had been issued but not yet adopted by us. Below is a discussion of the more significant standards that could impact us.

Accounting for Asset Retirement Obligations. In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, *Accounting for Asset Retirement Obligations.* This statement requires companies to record a liability for the estimated retirement and removal costs of long-lived assets used in their business. The liability is recorded at its fair value, with a corresponding asset which is depreciated over the remaining useful life of the long-lived asset to which the liability relates. An ongoing expense will also be recognized for changes in the value of the liability as a result of the passage of time. The provisions of SFAS No. 143 are effective for fiscal years beginning after June 15, 2002. We expect that we will record a charge as a cumulative effect of accounting change of approximately $21 million, net of income taxes, upon our adoption of SFAS No. 143 on January 1, 2003. We also expect to record non-current retirement assets of $106 million and non-current retirement liabilities of $135 million on January 1, 2003. Our liability relates primarily to our obligations to plug abandoned wells in our Production and Pipelines segments over the next four to 24 years.

Accounting for Costs Associated with Exit or Disposal Activities. In July 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* This statement will require us to recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. Examples of costs covered by this guidance include lease termination costs, employee severance costs associated with a restructuring, discontinued operations, plant closings or other exit or disposal activities. the statement is effective for fiscal years beginning after December 31, 2002, and will impact any exit or disposal activities we initiate after January 1, 2003.

Accounting for Guarantees. In November 2002, the FASB issued FASB Interpretation (FIN) No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*. This interpretation requires that companies record a liability for all guarantees issued after January 31, 2003, including financial, performance, and fair value guarantees. This liability is recorded at its fair value upon issuance, and does not affect any existing guarantees issued before January 31, 2003. This standard also requires expanded disclosures on all existing guarantees at December 31, 2002. We have included these required disclosures in Note 16.

Consolidation of Variable Interest Entities. In January 2003, the FASB issued FIN No. 46, *Consolidation of Variable Interest Entities,* an Interpretation of ARB No. 51. This interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity. This standard requires that companies consolidate a variable interest entity if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. The provisions of FIN No. 46 are effective for all variable interest entities created after January 31, 2003, and are effective on July 1, 2003 for all variable interest entities created before January 31, 2003. We have financial interests in several entities that we anticipate will be considered variable interest entities. They fall into two categories:

- Operating leases with residual value guarantees;
- Consolidated subsidiaries with preferred interests held by third party financial investors.

Operating leases with residual value guarantees. We have an operating lease on a facility at our Aruba refinery where we provide a guarantee to the lessor for the residual value of the facilities that we lease.

We believe we will consolidate the lessor under this arrangement on July 1, 2003 because (i) the equity investment by the third party investors (which are banks) is less than 10 percent of the total capitalization of the company that leases the facility to us, and (ii) because we guarantee a significant portion of the funds that were borrowed by the lessor to buy the facilities from us. When we consolidate the lessor of this facility, the assets owned by the lessor and the debt that supports the assets will be consolidated in our financial statements. In addition, these assets, once consolidated, will be subject to impairment testing under SFAS No. 144. Based on our preliminary analysis, we believe the impact on our financial statements will be to increase our total assets and long-term debt by approximately $350 million.

Consolidated subsidiaries with preferred interests held by third party investors. We currently have interests in and consolidate an entity in which third party investors hold preferred interests. The preferred interests held by the third party investors are reflected in our balance sheet as preferred securities in consolidated subsidiaries. The third party investors are capitalized with three percent equity, which is held by banks in these arrangements, and 97 percent debt. We believe we would consolidate these third party investors under these arrangements because (i) the equity investment in these third party investors is less than the specified 10 percent of total capitalization of the investors and (ii) the right of the third party investors to expected residual returns from these arrangements is limited. When we consolidate these third party investors, the minority interest that is currently classified as preferred securities in consolidated subsidiaries will be classified as long-term debt. Coastal Securities Company Limited is our consolidated subsidiary that will be impacted by this standard. We believe the impact on our financial statements will be (in millions):

Decrease in preferred securities of consolidated subsidiaries	$100
Increase in long-term debt	$100

For a further discussion of the consolidated subsidiaries potentially impacted by this pronouncement, see Note 15.

2. Merger and Divestitures

Merger with El Paso Corporation

In January 2001, we merged with El Paso Corporation (El Paso). In the merger, holders of our common stock and Class A common stock received 1.23 shares of El Paso common stock for each outstanding common share; holders of our Series A and Series B convertible preferred stock received 9.133 shares of El Paso common stock for each outstanding convertible preferred share; and holders of our Series C convertible preferred stock received 17.98 shares of El Paso common stock for each outstanding convertible preferred share. All these exchanges were done on a tax free basis. In addition, holders of our outstanding stock options received shares of El Paso common stock based on the fair value of these options on the date of the merger. As a result of the merger, El Paso owns 100 percent of our common equity.

Divestitures

During 2002 and 2003, we have completed or announced a number of asset sales in order to rationalize our business and address liquidity issues and changing market conditions. These sales occurred in all of our business segments as follows.

Segment	Proceeds	Pretax Gain (Loss)	Significant Assets and Investments Sold
	(In millions)		
Completed in 2002			
Pipelines	$ 303	$ 4	Natural gas and oil properties located in Texas, Kansas and Oklahoma and their related contracts 12.3 percent equity interest in Alliance Pipeline and related assets Typhoon natural gas pipeline
Production	1,297	(702)[(1)]	Natural gas and oil properties located in: South Texas Colorado Southeast Texas Utah Western Canada
Field Services	120	(14)	Dragon Trail processing plant 14.4 percent equity interest in Aux Sable NGL plant Gathering facilities located in Utah 50 percent equity interest in Blacks Fork facility
Merchant Energy	71	(3)	50 percent equity interest in petroleum products terminal NGL pipelines and fractionation facilities 14.4 percent equity interest in Alliance Canada Marketing L.P. Typhoon oil pipeline
Other	57	—	Coal reserves and properties in West Virginia, Virginia and Kentucky[(2)]
	$1,848	$(715)	

(1) We recognized a loss of $702 million, or $452 million net of income tax, on the sale of natural gas and oil properties in Utah. A loss was recognized on this sale because the reserves sold significantly altered the relationship between capitalized costs and proved reserves. We did not, however, recognize gains or losses on the remaining completed sales of natural gas and oil properties because individually they did not alter the relationship between capitalized costs and proved reserves at the time they were sold.

(2) During 2002, we recorded impairment charges of $185 million since the carrying value was higher than our estimated net sales proceeds. These properties are presented in our financial statements as discontinued operations. See Note 9 for further discussion.

Segment	Proceeds	Pretax Gain (Loss)	Significant Assets and Investments Sold
	(In millions)		
Announced or completed in 2003 (amounts are estimates) [1]			
Pipelines	$ 43	$ (1)	Panhandle gathering system in Texas 2.1 percent interest in Alliance pipeline and related assets
Production	178	— [2]	Natural gas and oil properties located in western Canada, New Mexico, Oklahoma and Mid-Continent region
Field Services	35	—	Gathering systems located in Wyoming
Merchant Energy	518	63	Corpus Christi refinery Florida petroleum terminals and tug and barge operations [3] Petroleum asphalt operations
Other	59	—	Remaining coal reserves and properties in West Virginia, Virginia and Kentucky [4]
	$ 833	$ 62	

(1) Sales that have been announced, but not completed, are subject to customary regulatory approvals and other conditions.
(2) We do not anticipate recognizing gains or losses on these sales of natural gas and oil properties because individually they will not significantly alter the relationship between capitalized costs and proved reserves at the time they are sold.
(3) The amount includes a $25 million receivable.
(4) Proceeds of $59 million consisted of $35 million in cash and $24 million in notes receivable.

In December 2002, we classified several of Field Service's small gathering systems located in Wyoming and Merchant Energy's Florida petroleum terminals and tug and barge operations to assets held for sale. We also classified our petroleum asphalt operations and lease crude business as held for sale. The total assets being sold had a net book value in property, plant and equipment of approximately $134 million. We reclassified these assets as other current assets as of December 31, 2002, since we plan to sell them in the next twelve months.

Under a Federal Trade Commission order, as a result of our January 2001 merger with El Paso, we sold our Gulfstream pipeline project, our 50 percent interest in the Stingray and U-T Offshore pipeline systems, and our investments in the Empire State and Iroquois pipeline systems. For the year ended December 31, 2001, net proceeds from these sales were approximately $184 million. We recognized extraordinary net losses of approximately $11 million, net of income taxes of approximately $5 million.

In February 2003, El Paso announced it would exit non-core businesses, including substantially all of our petroleum business (except our Aruba refinery). Since making this announcement, we have been identifying potential buyers for our petroleum assets. At this time, we cannot determine the amount of gain or loss, if any, that will be incurred. We will continue to evaluate whether these assets will be treated for accounting purposes as assets held for sale or possibly as discontinued operations.

3. Restructuring and Merger-Related Costs

During each of the years ended December 31, we incurred restructuring and merger-related costs as follows:

	2002	2001	2000
		(In millions)	
Restructuring costs	$ 5	$ —	$ —
Merger-related costs	—	814	13
	$ 5	$814	$ 13

Restructuring Costs

Our restructuring costs were incurred in connection with organizational restructurings in connection with El Paso's balance sheet and liquidity enhancement activities in 2002. In December 2001, El Paso announced a plan to strengthen its balance sheet, reduce costs and focus its activities on its core natural gas business. During 2002, we completed an employee restructuring across all of our operating segments, which resulted in a reduction of approximately 156 full-time positions through terminations. Through December 31, 2002, in our Merchant Energy segment, we had incurred and paid $5 million of employee severance and termination costs in connection with these actions.

Merger-Related Costs

During the year ended 2001, we incurred merger-related costs in connection with our merger with El Paso completed in January 2001 as follows:

2001	Pipelines	Production	Field Services	Merchant Energy	Other	Total
			(In millions)			
Employee severance, retention and transition costs	$ 76	$ 7	$ 2	$ 18	$480	$583
Business and operational integration costs	86	15	—	—	22	123
Other	30	23	11	26	18	108
Total merger-related costs	$192	$45	$13	$ 44	$520	$814

Employee severance, retention and transition costs include direct payments to, and benefit costs for, severed employees and early retirees that occurred as a result of our merger-related workforce reduction and consolidation. Following our merger with El Paso, we completed an employee restructuring across all of our operating segments, resulting in the reduction of 3,200 full-time positions through a combination of early retirements and terminations. Employee severance costs include actual severance payments and costs for pension and post-retirement benefits settled and curtailed under existing benefit plans as a result of these restructurings. Retention charges include payments to employees who were retained following the mergers and payments to employees to satisfy contractual obligations. Transition costs relate to costs to relocate employees and costs for severed and retired employees arising after their severance date to transition their jobs into the ongoing workforce.

Employee severance, retention, and transition costs for 2001 were approximately $583 million which included pension and post-retirement benefits of $214 million which were accrued at the merger date and will be paid over the applicable benefit periods of the terminated and retired employees. All other costs were expensed as incurred and have been paid. Also included in the 2001 employee severance, retention and transition costs was a charge of $278 million resulting from the issuance of approximately 4 million shares of El Paso common stock on the date of the our merger in exchange for the fair value of our employees' and directors' stock options and restricted stock. A total of 339 employees and 11 directors received these shares.

Business and operational integration costs include charges to consolidated facilities and operations of our business segments. Total charges in 2001 were $123 million. The charges include incremental fees under software and seismic license agreements of $15 million, which were recorded in our Production segment. Additional integration costs included approximately $108 million in estimated lease-related costs to relocate our pipeline operations from Detroit, Michigan to Houston, Texas. In addition, asset impairment charges of $13 million were incurred related to the closure of this facility. These charges were incurred in both our Pipeline and Corporate segments. These charges were accrued at the time we completed our relocations and closed these offices. The amounts accrued will be paid over the term of the applicable non-cancelable lease agreements. All other costs were expensed as incurred.

Other costs for 2001 were $108 million which include payments made in satisfaction of obligations arising from the FTC approval of our merger with El Paso and other miscellaneous charges. These items were expensed in the period in which they were incurred.

Merger-related costs incurred in 2000 were related to transaction costs, which included investment banking, legal, accounting, consulting and other advisory fees incurred to obtain federal and state regulatory approvals and take other actions necessary to complete the merger. All of these items were expensed in the periods in which they were incurred.

4. Gain (Loss) on Long-Lived Assets

Gain (loss) on long-lived assets consist of realized gains and losses on sales of long-lived assets and impairments of long-lived assets. During each of the years ended December 31, our gains (losses) on long-lived assets were as follows:

	2002	2001	2000
		(In millions)	
Realized gain (loss)	$(650)	$ (7)	$ 18
Asset impairments	(141)	(168)	(13)
Gain (loss) on long-lived assets	$(791)	$(175)	$ 5

Realized Gain (Loss)

Our realized gain (loss) on sales of long-lived assets for the years ended December 31, 2002, 2001 and 2000, were $(650) million, $(7) million and $18 million. Our 2002 loss was primarily a result of losses related to the sales of natural gas and oil properties located in Utah in our Production segment, and the sale of our Natural Buttes gathering system, our Ouray gathering system and our Dragon Trail processing plant in our Field Services segment. See Note 2 for a further discussion of these divestitures. Our 2001 losses related to miscellaneous asset sales across all our segments and our 2000 gain related to the sale of a portion of our Montreal paraxylene plant in our Merchant Energy segment.

Asset Impairments

During the years ended December 31, we incurred asset impairment charges in our business segments as follows:

Segment and Asset Description	Amount (In millions)	Cause of Impairment
2002		
Production		
Intangible asset	$ 4	Sale of underlying properties
Total Production	4	
Field Services		
Goodwill impairment	14	Sale of assets in the segment
Total Field Services	14	
Merchant Energy		
MTBE chemical processing plant	91	MTBE was banned in our largest market. Decision to eliminate future capital spending to refit plant for alternative fuel uses
Power turbines	18	Scaled down capital spending in new power facilities and weak economic conditions in the power sector
Solarc project	14	Decision to discontinue future capital investment
Total Merchant Energy	123	
Total 2002 asset impairments	$141	
2001		
Pipelines		
Renaissance Center leasehold improvements	$ 9	Relocation of Detroit headquarters
Supply Link projects	7	Decision following the El Paso merger not to pursue these projects
Other projects	6	Decision following the El Paso merger not to pursue these projects
Total Pipelines	22	
Production		
Australian and Indonesian assets	16	Decision following the El Paso merger not to drill in these areas
Total Production	16	
Merchant Energy		
Oyster Creek chemical facility	37	Facility shut down following the El Paso merger
Kansas refining operations	35	Refinery closed as a result of sale of retail outlets in the midwest
Capitalized development costs	20	Decision not to pursue projects following the El Paso merger
Other merchant assets	24	Change in strategy and business decisions following merger
Corpus Christi refinery	8	Lease of Corpus Christi refinery to Valero Energy Corporation
Total Merchant Energy	124	
Corporate and Other		
Miscellaneous corporate assets	6	Relocation of Detroit headquarters
Total Corporate and Other	6	
Total 2001 asset impairments	$168	
2000		
Merchant Energy		
Florida and other refining assets	$ 13	Decision not to pursue development on these projects
Total Merchant Energy	13	
Total 2000 asset impairments	$ 13	

Our impairment charges were based on reducing the carrying value of these assets to their estimated fair value. Fair value was determined through a combination of estimating the proceeds from the sale of the asset, less anticipated selling costs (if we intend to sell the asset), or the discounted estimated cash flows of the asset based on current and anticipated future market conditions (if we intend to hold the asset).

5. Changes in Accounting Estimates

Included in our operation and maintenance costs for the twelve months ended December 31, 2001 were approximately $316 million in costs related to changes in accounting estimates which consist of $232 million in additional environmental remediation liabilities, $47 million in additional accrued legal obligations and a $37 million charge to reduce the value of our spare parts inventories to reflect changes in the usability of these parts in our worldwide operations. The change in our estimated environmental remediation liabilities was due to a number of events including $109 million resulting from the sale of a majority of our retail gas stations, $31 million related to our closure of our Gulf Coast Chemical and Midwest refining operations, $10 million associated with the lease of our Corpus Christi refinery to Valero, and $82 million associated with conforming our methods of environmental identification, assessment and remediation strategies and processes to El Paso's historical practices following our merger with El Paso. This accounted for the remainder of the change in estimated obligations. The change in estimate of our legal obligations was a result of a review process to assess our legal exposures, strategies and plans following the merger with El Paso. Finally, the charge related to our spare parts inventories was primarily the result of several events that occurred as part of and following our merger with El Paso, including the consolidation of numerous operation locations, the sale of a majority of our retail gas stations, the shutdown of our Midwest refining operations and the lease of our Corpus Christi refinery. These changes were also a direct result of a fire at our Aruba refinery whereby a portion of the plant was rebuilt following the fire rendering many of these parts unusable. Also impacting these amounts was the evaluation of the operating standards, strategies and plans of our combined company following the merger. Our changes in estimates are included as operating expenses in our income statement and reduced our net income before extraordinary items and net income for the year ended December 31, 2001 by approximately $241 million.

6. Ceiling Test Charges

Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests to evaluate whether the carrying value of natural gas and oil properties exceeds the present value of future net revenues, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties, net of related income tax effects.

For the year ended December 31, 2002, we recorded ceiling test charges of $245 million, of which $10 million was charged during the first quarter, $233 million was charged during the second quarter, and $2 million was charged during the fourth quarter. The write-down includes $226 million for our Canadian full cost pool, $10 million for our Brazilian full cost pool and $9 million for other international production operations, primarily in Australia. Our third quarter charges were based on the daily posted natural gas and oil prices as of November 1, 2002, adjusted for oilfield or natural gas gathering hub and wellhead price differences as appropriate. Had we computed the ceiling test charges based upon the daily posted natural gas and oil prices as of September 30, 2002, we would have incurred a charge of $96 million relating to our domestic full cost pool. The charge for the Canadian full cost pool primarily resulted from a low daily posted price for natural gas at June 30, 2002, which was approximately $1.43 per MMbtu.

For the year ended December 31, 2001, we recorded ceiling test charges of $115 million, including $87 million for our Canadian full cost pool and $28 million for our Brazilian full cost pool. Our 2001 charges were based on the daily posted natural gas and oil prices as of November 1, 2001, adjusted for oilfield or natural gas gathering hub and wellhead price differences as appropriate. Had we computed the third quarter 2001 ceiling test charges based upon the daily posted natural gas and oil prices as of September 30, 2001, we would have incurred a ceiling test charge of $255 million. This amount would have included $227 million for our Canadian full cost pool and $28 million for our Brazilian full cost pool.

We use financial instruments to hedge against the volatility of natural gas and oil prices. The impact of these hedges was considered in determining our ceiling test charges, and will be factored into future ceiling test calculations. Had the impact of our hedges not been included in calculating our ceiling test charges, we would have incurred a charge of $125 million for the nine months ended September 30, 2002, and $830 million for the nine months ended September 30, 2001, relating to our domestic full cost pool. The charges for our international cost pools would not have materially changed since we do not significantly hedge our international production activities.

7. Other Income and Other Expenses

Following are the components of other income and other expenses for each of the three years ended December 31:

	2002	2001	2000
		(In millions)	
Other Income			
Favorable resolution of non-operating contingent obligations	$ 31	$ 4	$ 5
Property losses and insurance	26	60	—
Rental income	18	35	21
Development, management and administrative services fees on power projects	14	18	19
Interest income	13	28	34
Income from retail operations	—	4	15
Other	16	41	32
Total	$118	$190	$126
Other Expenses			
Miscellaneous balancing adjustments	$ 13	$ 12	$ —
Foreign currency loss	3	1	—
Penalty and legal expenses	3	1	—
Other	18	14	10
Total	$ 37	$ 28	$ 10

8. Income Taxes

Pretax income (loss) from continuing operations before extraordinary items and cumulative effect of accounting change are composed of the following for each of the three years ended December 31:

	2002	2001	2000
		(In millions)	
United States	$ (168)	$(129)	$723
Foreign	(40)	38	185
	$ (208)	$ (91)	$908

The following table reflects the components of income tax expense (benefit) included in income (loss) from continuing operations before extraordinary items and cumulative effect of accounting change for each of the three years ended December 31:

	2002	2001	2000
		(In millions)	
Current			
Federal	$ (58)	$104	$ 42
State	2	(5)	(1)
Foreign	10	6	9
	(46)	105	50
Deferred			
Federal	68	28	189
State	44	(15)	11
Foreign	(101)	(37)	3
	11	(24)	203
Total income tax expense (benefit)	$ (35)	$ 81	$253

Our tax expense (benefit), included in income (loss) from continuing operations before extraordinary items and cumulative effect of accounting change, differs from the amount computed by applying the statutory federal income tax rate of 35 percent for the following reasons for each of the three years ended December 31:

	2002	2001	2000
		(In millions)	
Tax expense (benefit) at the statutory federal rate of 35%	$(73)	$(32)	$318
Increase (decrease)			
Tight sands gas credit	—	—	(6)
State income taxes	30	(13)	6
Foreign income taxed at different tax rates	(2)	(2)	(48)
Depreciation, depletion and amortization	—	20	(17)
Goodwill impairment	5	—	—
Non-deductible portion of merger costs and other tax adjustments to provide for revised estimated liabilities	—	106	—
Non-deductible dividends on preferred stock of subsidiaries	2	3	4
Other	3	(1)	(4)
Income tax expense (benefit)	$(35)	$ 81	$253
Effective tax rate	17%	(89)%	28%

The following are the components of our net deferred tax liability of continuing operations as of December 31:

	2002	2001
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$1,904	$1,771
Investments in unconsolidated affiliates	216	255
Price risk management activities	—	173
Other assets	108	507
Total deferred tax liability	2,228	2,706
Deferred tax assets		
U.S. net operating loss and tax credit carryovers	217	256
Environmental liability	57	99
Price risk management activities	53	—
Other liabilities	254	576
Total deferred tax asset	581	931
Net deferred tax liability	$1,647	$1,775

At December 31, 2002, the portion of the cumulative undistributed earnings of our foreign subsidiaries and foreign corporate joint ventures on which we have not recorded U.S. income taxes was approximately $964 million. Since these earnings have been or are intended to be indefinitely reinvested in foreign operations, no provision has been made for any U.S. taxes or foreign withholding taxes that may be applicable upon actual or deemed repatriation. If a distribution of these earnings were to be made, we might be subject to both foreign withholding taxes and U.S. income taxes, net of any allowable foreign tax credits or deductions. However, an estimate of these taxes is not practicable. For these same reasons, we have not recorded a provision for U.S. income taxes on the foreign currency translation adjustment recorded in other comprehensive income.

The tax benefit associated with the exercise of non-qualified stock options and the vesting of restricted stock, as well as restricted stock dividends, reduced taxes payable by $2 million in 2002, $5 million in 2001 (allocated to us in both years under El Paso's tax accrual policy), and $18 million in 2000. These benefits are included in additional paid-in capital in our balance sheets.

As of December 31, 2002, we had alternative minimum tax credits of $217 million that carryover indefinitely. Usage of these carryovers is subject to the limitations provided under Section 383 of the Internal Revenue Code as well as the separate return limitation year rules of IRS regulations.

9. Discontinued Operations

In June 2002, our parent's Board of Directors authorized the sale of our coal mining operations. These operations, which have historically been included in our Merchant Energy segment, consist of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. Following the authorization of the sale by our parent's Board of Directors, we compared the carrying value of the underlying assets to our estimated sales proceeds, net of estimated selling costs, based on bids received in the sale process in the second and third quarters of 2002. Because this carrying value was higher than our estimated net sales proceeds, we recorded impairment charges of $148 million in the second quarter of 2002 and $37 million in the third quarter of 2002.

In December 2002, we sold substantially all of our reserves and properties in West Virginia, Virginia and Kentucky to an affiliate of Natural Resources Partners, L.P. for $57 million in cash. In January 2003, we sold our remaining coal operations, which consists of mining operations, businesses, properties and reserves in Kentucky, West Virginia and Virginia, to subsidiaries of Alpha Natural Resources, LLC, an affiliate of First Reserve Corporation, for $59 million which includes $35 million in cash and $24 million in notes receivable.

Our coal mining operations have been classified as discontinued operations in our financial statements for all periods presented. In addition, we reclassified all of the assets and liabilities of our remaining coal mining operations as of December 31, 2002 to other current assets and liabilities. The summarized financial results of discontinued operations for each of the three years ended December 31, are as follows:

	2002	2001	2000
		(In millions)	
Operating Results:			
Revenues	$ 309	$ 277	$ 276
Costs and expenses	(327)	(286)	(270)
Asset impairments	(185)	—	(8)
Other income, net	6	2	1
Loss before income taxes	(197)	(7)	(1)
Income tax benefit	73	2	—
Loss from discontinued operations, net of income taxes	$(124)	$ (5)	$ (1)

	December 31,	
	2002	2001
	(In millions)	
Financial Position Data:		
Assets of discontinued operations		
Accounts receivable	$ 29	$ 35
Inventory	14	11
Property, plant and equipment, net	46	301
Other	17	5
Total assets	$106	$352
Liabilities of discontinued operations		
Accounts payable and other	$ 25	$ 37
Environmental remediation reserve	15	—
Total liabilities	$ 40	$ 37

10. Financial Instruments

Following are the carrying amounts and estimated fair values of our financial instruments as of December 31:

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(In millions)		
Long-term debt and other obligations, including current maturities	$5,354	$4,637	$6,417	$6,477
Notes payable to unconsolidated affiliates	—	—	67	67
Company obligated preferred securities of subsidiaries	300	160	300	299
Trading price risk management activities	(18)	(18)	(23)	(23)
Non-trading price risk management activities	822	822	501	501

As of December 31, 2002 and 2001, our carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables are representative of fair value because of the short-term nature of these instruments. The fair value of long-term debt with variable interest rates approximates its carrying value because of the market-based nature of the debt's interest rates. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues. We estimated the fair value of all derivative financial instruments based on quoted market prices, current market conditions, estimates we obtained from third-party brokers or dealers, or amounts derived using valuation models.

11. Price Risk Management Activities

The following table summarizes the carrying value of our trading and non-trading price risk management assets and liabilities as of December 31:

	2002	2001
	(In millions)	
Net assets (liabilities)		
Trading contracts[1]	$(18)	$(23)
Non-trading contracts		
Derivatives designated as hedges	(146)	501
Other derivatives	968	—
Net assets from price risk management activities[2]	$804	$478

(1) Trading contracts are those that are entered into for purposes of generating a profit or benefiting from movements in market prices.

(2) Net assets from price risk management activities include current and non-current assets and current and non-current liabilities from price risk management activities on the balance sheet.

Included in other derivatives as of December 31, 2002, are $968 million of derivative contracts related to the power restructuring activities of our consolidated subsidiaries. Of this amount, $878 million relates to a power restructuring that occurred during the first quarter of 2002 at our Eagle Point Cogeneration power plant, and $90 million relates to a power restructuring at our Capitol District Energy Center Cogeneration Associates plant.

Trading Activities and Contracts. Our trading activities include the services we provide in the energy sector that we enter into with the objective of generating profits on or benefiting from movements in market prices, primarily related to the purchase and sale of energy commodities.

We have reflected our trading portfolio at estimated fair value which is the amount at which the contracts in our portfolio could be bought or sold in a current transaction between willing buyers and sellers. We obtained valuation assistance from a third party valuation specialist in determining the fair value of our trading and non-trading price risk management activities as of December 31, 2002. Based upon the specialist's input, our estimates of fair value are based upon price curves derived from actual prices observed in the market, pricing information supplied by the specialist and independent pricing sources and models that rely on this forward pricing information and historical information. These estimates may also reflect factors for time value and volatility underlying the contracts, the potential impact of liquidating our position in an orderly manner over a reasonable time under present market conditions, modeling risk, credit risk of our counterparties and operational risks, as needed.

We serve a diverse group of customers that require a wide variety of financial structures, products and terms. This diversity requires us to manage, on a portfolio basis, the resulting market risks inherent in our trading price risk management activities subject to parameters established by our risk management committee. We monitor market risks through a risk control committee operating independently from the units that create or actively manage these risk exposures to ensure compliance with our stated risk management policies. We measure and adjust the risk in accordance with mark-to-market and other risk management methodologies which utilize forward price curves in the energy markets to estimate the size and probability of future potential exposure.

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We maintain credit policies with regard to our counterparties in both our trading and non-trading price risk management activities to minimize overall credit risk. These policies require an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances (including cash in advance, letters of credit, and guarantees), and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Substantially all of our trading and non-trading price risk management activities that are in net asset positions are with investment grade energy marketers, financial institutions and natural gas and electric utilities at December 31, 2002 and 2001.

Non-trading Activities — Derivatives Designated as Hedges.

We use derivative financial instruments to hedge the impact of our market price risk exposures on our assets, liabilities, contractual commitments and forecasted transactions related to our natural gas and oil production, refining, natural gas transmission, power generation, financing and international business activities. We engage in two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Hedges of fair value exposure are entered into to hedge the fair value of a recognized asset, liability or firm commitment. On the date that we enter into the derivative contract, we designate the derivative as either a cash flow hedge or a fair value hedge. Changes in derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings as a component of operating revenues in our income statement. Changes in the derivative fair values that are designated as fair value hedges are recognized in earnings as offsets to the changes in fair values of related hedged assets, liabilities or firm commitments.

As required by SFAS No. 133, we formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or fair values of the hedged items. We discontinue hedge accounting prospectively if we determine that a derivative is no longer highly effective as a hedge or if we decide to discontinue the hedging relationship.

The fair value of our hedging instruments reflects our best estimate and is based upon exchange or over-the-counter quotations when they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to make estimations of future prices, price correlation and market volatility and liquidity. Our actual results may differ from our estimates, and these differences can be positive or negative.

On January 1, 2001, we adopted the provisions of SFAS No. 133 and recorded a cumulative-effect adjustment of $459 million, net of income taxes, in accumulated other comprehensive income to recognize the fair value of all derivatives designated as hedging instruments. The majority of the initial charge related to hedging cash flows from anticipated sales of natural gas for 2001 and 2002. During the year ended December 31, 2001, $456 million, net of income taxes, of this initial transition adjustment was reclassified to earnings as a result of hedged sales and purchases during the year. A discussion of our hedging activities is as follows:

Fair Value Hedges. We have crude oil and refined products inventories that change in value daily due to changes in the commodity markets. We use futures and swaps to protect the value of these inventories. For the years ended December 31, 2002 and 2001, the financial statement impact of our hedges of the fair value of these inventories was immaterial.

Cash Flow Hedges. A majority of our commodity sales and purchases are at spot market or forward market prices. We use futures, forward contracts and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities. As of December 31, 2002 and 2001, the value of cash flow hedges included in accumulated other comprehensive income was a net unrealized loss of $79 million and a net unrealized gain of $318 million, net of income taxes. We estimate that unrealized losses of $117 million, net of income taxes, will be reclassified from accumulated other comprehensive income during 2003. Reclassifications occur upon physical delivery of the hedge commodity and the corresponding expiration of the hedge. The maximum term of our cash flow hedges is three years; however, most of our cash flow hedges expire within the next 12 months.

Our accumulated other comprehensive income as of December 31, 2002 and 2001 also includes a gain of $17 million and $1 million, net of income taxes, representing our proportionate share of amounts recorded in other comprehensive income by our unconsolidated affiliates who use derivatives as cash flow hedges. Included in this gain is a $9 million gain that we estimate will be reclassified from accumulated other comprehensive income during 2003. The maximum term of these cash flow hedges is two years, excluding hedges related to interest rates on variable debt.

For the years ended December 31, 2002 and 2001, we recognized net losses of $3 million and $1 million, net of income taxes, related to the ineffective portion of all cash flow hedges.

In May 2002, we announced a plan to reduce the volumes of natural gas that we have hedged for our Production segment, and we removed the hedging designation on derivatives that had a fair value loss of $85 million at December 31, 2002. This amount, net of income taxes of $30 million, is reflected in accumulated other comprehensive income and will be reclassified to income as the original hedged transactions are settled through 2004. Of the net loss of $55 million in accumulated other comprehensive income, we estimate that unrealized losses of $29 million, net of income taxes, related to these derivatives will be reclassified to income over the next twelve months.

Non-trading Activities — Power Restructuring Activities. Our Merchant Energy segment's power restructuring activities involve amending or terminating a power plant's existing power purchase contract to eliminate the requirement that the plant provide power from its own generation to the regulated utility and replacing that requirement with the ability to provide power to the utility from the wholesale power market. In conjunction with our power restructuring activities, we generally entered into new market-based contracts with third parties to provide the power to the utility from the wholesale power market, which effectively "locks in" our margin on the restructuring transaction as the difference between the contracted rate in the restructured contract and the wholesale market rates at the time.

Prior to a restructuring, the power plant and its related power purchase contract are generally accounted for at their historical cost, which is either the cost of construction or, if acquired, the acquisition cost. Revenues and expenses prior to the restructuring are, in most cases, accounted for on an accrual basis as power is generated and sold to the utility.

Following a restructuring, the accounting treatment for the power purchase agreement can change if the restructured contract meets the definition of a derivative and is therefore required to be market to its fair value under SFAS No. 133. In addition, since the power plant no longer has the exclusive right to provide power under the original, dedicated power purchase contract, it operates as a peaking merchant plant, generating power only when it is economical to do so. Because of this significant change in its use, the fair value of the plant may be less than its historical value. These changes may also require us to terminate or amend any related fuel supply and steam agreements, and enter into other third party and intercompany contracts such as transportation agreements, associated with the operations of the facility.

Our power restructuring activities have the following effects to our financial statements:

- The restructured contract (if it meets the definition of a derivative) is shown as an asset from price risk management activities in our balance sheet.

- The difference between the fair value of the restructured contract and the carrying value of the original contract is shown as operating revenues in our income statement. Any subsequent changes in this fair value are also recorded in operating revenues.
- The new third party wholesale power supply and other contracts are recorded at their fair value as liabilities from price risk management activities in our balance sheet. Any subsequent changes in the fair value are also recorded in operating revenues.
- The carrying value of the underlying power plant and any related intangible assets are evaluated for impairment and, if required, are written down to their value as a merchant power plant, which is recorded as operating expenses in our income statement.
- Any contract termination fees and closing costs are also recorded as operating expenses in our income statement.
- As we purchase power under the wholesale power supply contracts, we record the cost of the power we purchase as operating expenses in our income statement.
- As we sell that power to the utility under the restructured contract, we record the amounts received under the contract as operating revenues.

We classify our restructured contracts as non-trading price risk management activities in our disclosures.

In 2002 we completed a power restructuring on our Eagle Point Cogeneration facility, which we consolidate, and applied the accounting described above to that transaction. We also employed the principles of our power restructuring business in reaching a settlement in 2002 of the dispute under our Nejapa power contract which included a cash payment to us. We recorded these payments as operating revenues. As of and for the year ended December 31, 2002, our consolidated power restructuring activities had the following effects on our consolidated financial statements (in millions):

	Assets from Price Risk Management Activities	Liabilities from Price Risk Management Activities	Property, Plant and Equipment and Intangible Assets	Operating Revenues	Operating Expenses	Increase (Decrease) Minority Interest
Initial gain on restructured contracts	$978	$ 80		$ 988		$ 172
Writedown of power plants and intangibles and other fees			$(328)		$489	(109)
Change in value of restructured contracts during 2002	8			(96)		(20)
Change in value of third party wholesale power supply contracts		(62)		62		(3)
Purchase of power under power supply contracts					47	(11)
Sale of power under restructured contracts				111		28
Total	$986	$ 18	$(328)	$1,065	$536	$ 57

The fair value of the derivatives related to our power restructuring activities is determined based on the expected cash receipts and payments under the contracts using future power prices compared to the contractual prices under these contracts. We discount these cash flows at an interest rate commensurate with the term of each contract and the credit risk of each contract's counterparty. We make adjustments to this discount rate when we believe that market changes in the rates result in changes in fair values that can be realized. We consider whether changes in the rates are the result of changes in the capital markets, or are the result of sustained economic changes. Future power prices are based on the forward pricing curve of the appropriate power delivery and receipt points in the applicable power market. This forward pricing curve is derived from available market data and pricing information supplied by a third party. The timing of cash receipts and payments are based on the expected timing of power delivered under these contracts. The fair value of our derivatives may change each period based on changes in actual and projected market prices, fluctuations in the credit ratings of our counterparties, significant changes in interest rates, and changes to the assumed timing of deliveries.

As a result of credit downgrades and disruptions in the capital markets, it is unlikely we will pursue additional power restructurings in the near term.

12. Inventory

Our inventory consisted of the following at December 31:

	2002	2001
	(In millions)	
Current		
Refined products, crude oil and chemicals	$584	$576
Materials and supplies and other	113	107
Total current inventory	697	683
Non-Current		
Turbines	20	38
Total	$717	$721

13. Property, Plant and Equipment

At December 31, 2002 and 2001, we had approximately $1,127 million and $1,141 million of construction work in progress included in our property, plant and equipment.

In June 2001, we entered into a 20-year lease agreement related to our Corpus Christi refinery and related assets with Valero. Under the lease, Valero pays us a quarterly amount that increases after the second year of the lease. For the years ended December 31, 2002 and 2001, we recorded $19 million and $11 million in lease income related to this lease. In February 2003, Valero exercised its option to purchase the plant and related assets for $289 million in cash. We recorded a gain of $8 million.

As of December 31, 2002, ANR has excess purchase costs associated with its acquisition. Total excess costs were approximately $2 billion and accumulated depreciation was approximately $924 million. These excess costs are being amortized over the life of the related pipeline assets, and our amortization expense during 2002 was approximately $34 million. The adoption of SFAS No. 142 did not impact this amount since it was included as part of our property, plant and equipment, rather than as goodwill.

We have goodwill recorded as a result of the acquisitions of ANR and CIG. This goodwill was $723 million at December 31, 2002, and $310 million of accumulated amortization. In conjunction with adoption of SFAS 142 on January 1, 2002, we ceased our amortization of this goodwill and performed the required impairment tests on this goodwill. No impairment of this goodwill was indicated as of January 1, 2002 and December 31, 2002.

14. Debt, Other Financing Obligations and Other Credit Facilities

At December 31, 2001, our weighted average interest rate on our short-term credit facilities was 2.4%, and there were no amounts outstanding under these facilities at December 31, 2002. We had the following short-term borrowings and other financing obligations at December 31:

	2002	2001
	(In millions)	
Current maturities of long-term debt and other financing obligations	$369	$1,310
Notes payable to unconsolidated affiliates	—	67
Short-term credit facilities	—	30
Other	—	3
	$369	$1,410

Credit Facilities

In June 2002, El Paso amended its existing $1 billion 3-year revolving credit and competitive advance facility to permit El Paso to issue up to $500 million in letters of credit and to adjust pricing terms. This facility matures in August 2003. We are a designated borrower under this facility and, as such, are jointly and severally liable for any amounts outstanding under this facility. The interest rate varies based on El Paso's senior unsecured debt rating, and as of December 31, 2002, an initial draw would have had a rate of LIBOR plus 1.00% plus a 0.25% utilization fee. As of December 31, 2002, there were no borrowings outstanding, and $456 million in letters of credit were issued under the $1 billion facility. In February 2003, El Paso borrowed $500 million under the $1 billion facility.

Restrictive Covenants

We have entered into debt instruments and guaranty agreements that contain covenants such as restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on sales of assets, capitalization requirements, dividend restrictions and cross-acceleration provisions. A breach of any of these covenants could accelerate our debt and other financial obligations and that of our subsidiaries.

One of the most significant debt covenants is that we must maintain a minimum net worth of $1.2 billion. If breached, the amounts guaranteed by the guaranty agreements could be accelerated. The guaranty agreements also have a $30 million cross-acceleration provision.

In addition, we have indentures associated with our public debt that contain $5 million cross-acceleration provisions.

2003 Activities

In January 2003, we retired various debt obligations of approximately $47 million. In February 2003, Valero exercised its option to purchase our Corpus Christi refinery and we used the proceed to repay a $240 million loan that was secured by the refinery lease with Valero.

In March, 2003, ANR issued $300 million of 8⅞% senior unsecured notes due 2010, raising net proceeds of $288 million. ANR used $263 million of cash proceeds from the offering to reduce existing intercompany payables. ANR retained $25 million of net proceeds from the offering to fund future capital expenditures.

Our long-term debt and other financing obligations outstanding consisted of the following at December 31:

	2002	2001
	(In millions)	
Long-term debt		
El Paso CGP		
Senior notes, 6.2% through 8.125%, due 2002 through 2010	$1,305	$1,565
Floating rate senior notes, due 2002 and 2003[1]	200	600
Senior debentures, 6.375% through 10.75%, due 2003 through 2037	1,497	1,497
FELINE PRIDES, 6.625% due 2004	—	460
Valero lease financing loan due 2004[2]	240	240
El Paso Power		
Non-recourse senior notes, 7.75% and 7.944%, due 2008 and 2016	915	—
Non-recourse notes 8.5%, due 2005	126	—
El Paso Production Company		
Floating rate notes, due 2005 and 2006	200	200
ANR Pipeline		
Debentures, 7.0% through 9.625%, due 2021 through 2025	500	500
Notes, 13.75% due 2010	13	—
Colorado Interstate Gas		
Debentures, 6.85% and 10.0%, due 2005 and 2037	280	280
Other	84	369
	5,360	5,711
Less:		
Unamortized discount	6	9
Current maturities	369	720
Long-term debt, less current maturities	4,985	4,982
Other Financing Obligations		
Crude oil prepayments[3]	—	500
Natural gas production payment	—	215
	—	715
Less:		
Current maturities	—	590
Other financing obligations, less current maturities	—	125
Total long-term debt and other financing obligations, less current maturities	$4,985	$5,107

(1) In March 2002, we retired $400 million of these notes.

(2) Collateralized by the lease payments from Valero under their lease of our Corpus Christi refinery. The Valero loan was repaid in February 2003.

(3) Secured by our agreement to deliver a fixed quantity of crude oil to a specified delivery point in the future. As of December 31, 2002, all of the crude oil prepayment obligations had been paid.

Aggregate maturities of the principal amounts of long-term debt and other financing obligations for the next 5 years and in total thereafter are as follows (in millions):

2003	$ 369
2004	556
2005	364
2006	655
2007	60
Thereafter	3,356
Total long-term debt and other financing obligations including current maturities	$5,360

In July 2002, Utility Contract Funding issued $829 million of 7.944% senior secured notes due in 2016. This financing is non-recourse to other El Paso companies, as it is independently supported only by the cash flows and contracts of Utility Contract Funding including obligations of Public Service Electric and Gas under a restructured power contract and of Morgan Stanley under a power supply agreement. In connection with the credit enhancement provided by Morgan Stanley's participation, we paid them $36 million in consideration for entering into the supply agreement.

In August 2002, El Paso issued 12,184,444 shares of common stock to satisfy purchase contract obligations under our FELINE PRIDES℠ program. In return for the issuance of the stock, we received approximately $25 million in cash from the maturity of a zero coupon bond and the return of $435 million of our existing 6.625% senior debentures due August 2004 that were issued in 1999. The zero coupon bond and the senior debentures had been held as collateral for the purchase contract obligations. The $25 million received from the maturity of the zero coupon bond was used to retire additional senior debentures. Total debt reduction from the issuance of the common stock was approximately $460 million.

Other Financing Arrangements

During 2000, El Paso formed a series of companies that it refers to as Clydesdale. Clydesdale was formed to provide financing to invest in various capital projects and other assets. A third-party investor contributed cash of $1 billion into Clydesdale in exchange for the preferred securities of one of El Paso's consolidated subsidiaries. The financing arrangement is collateralized by a combination of notes payable from us, various natural gas and oil properties, a production payment from us and our wholly owned subsidiary Colorado Interstate Gas Company. The credit downgrades of El Paso have resulted in the net cash generated by these assets being largely unavailable to us for general corporate purposes. The cash generated by these assets can only be used to redeem the preferred securities issued in connection with these arrangements, and for the operations of the business units associated with this transaction. As of December 31, 2002, the total amount outstanding on the Clydedale transaction was $950 million.

In a series of credit rating agency actions in late 2002 and early 2003, and contemporaneously with the downgrades of the senior unsecured indebtedness of El Paso, our senior unsecured indebtedness was downgraded below investment grade and is currently rated Caa1 by Moody's and B by Standard & Poor's and we remain on negative credit outlook. These downgrades will increase our cost of capital and collateral requirements and could impede our access to capital markets in the future.

Other Financial Activities

Our significant long-term debt borrowing and repayment activities during 2002 were as follows:

Date	Company	Type	Interest Rate	Principal	Net Proceeds	Due Date
				(In millions)		
Issuances						
2002						
April	Mohawk River Funding IV(1)	Senior secured notes	7.75%	$ 92	$ 90	2008
July	Utility Contract Funding(1)	Senior secured notes	7.944%	829	792	2016
Retirements						
2002						
March	El Paso CGP	Long-term debt	Variable	$400	$400	2002
June	El Paso CGP	Crude oil prepayment	Variable	300	300	2002
June	El Paso CGP	Long-term debt	Variable	90	90	2002
Jan.-June	El Paso Oil & Gas Resources	Natural gas production payment	Variable	215	215	2002-2005
July	El Paso CGP	Long-term debt	Variable	55	55	2002
August	El Paso CGP(2)	Long-term debt	6.20%	10	9	2004
August	El Paso CGP	Long-term debt	6.625%	460	25(3)	2004
June-Aug.	El Paso CGP	Long-term debt	Variable	51	51	2010-2028
September	El Paso CGP	Long-term debt	8.125%	250	250	2002
Jan.-Sept.	El Paso CGP	Long-term debt	Variable	106	106	2002

Date	Company	Type	Interest Rate	Principal	Net Proceeds	Due Date
				(In millions)		
Jan.-Sept.	Various	Long-term debt	Various	30	30	2002
November	El Paso CGP	Long-term debt	Variable	60	60	2002
Oct.-Dec.	El Paso CGP	Crude Oil prepayment	Various	200	200	2002

(1) These notes are collateralized solely by the cash flows and contracts of these consolidated subsidiaries, and are non-recourse to our parent and other affiliated companies. The Mohawk River Funding IV financing relates to our Capitol District Energy Center Cogeneration Associates restructuring transaction, and the Utility Contract Funding financing relates to our Eagle Point Cogeneration restructuring transaction.

(2) These amounts represent a buyback of our bonds in the open market in July and August 2002.

(3) The majority of this debt was exchanged for El Paso common stock.

15. Preferred Interests of Consolidated Subsidiaries

In the past, we entered into financing transactions that have been accomplished through the sale of preferred interests in consolidated subsidiaries. Total amounts outstanding under these programs at December 31, 2002 and 2001, were as follows (in millions):

	2002	2001
Coastal Finance I consolidated trust	$300	$300
Preferred stock of subsidiaries	100	165
Consolidated partnership	—	285
	$400	$750

Coastal Finance I. Coastal Finance I is a wholly owned business trust formed in May 1998. Coastal Finance I completed a public offering of 12 million mandatory redemption preferred securities for $300 million. Coastal Finance I holds subordinated debt securities issued by us that it purchased with the proceeds of the preferred securities offering. Cumulative quarterly distributions are being paid on the preferred securities at an annual rate of 8.375% of the liquidation amount of $25 per preferred security. Coastal Finance I's only source of income is interest earned on these subordinated debt securities. This interest income is used to pay the obligations on Coastal Finance I's preferred securities. The preferred securities are mandatorily redeemable on the maturity date, May 13, 2038, and may be redeemed at our option on or after May 13, 2003, or earlier if various events occur. The redemption price to be paid is $25 per preferred security, plus accrued and unpaid distributions to the date of redemption. We provide a guarantee of the payment of obligations of Coastal Finance I related to its preferred securities to the extent Coastal Finance I has funds available.

Coastal Securities Company Preferred Stock. In 1996, Coastal Securities Company Limited, our wholly owned subsidiary, issued 4 million shares of preferred stock for $100 million to Cannon Investors Trust, which is an entity comprised of a consortium of banks. Quarterly cash dividends are being paid on the preferred stock at a rate based on LIBOR plus a margin of 2.11% based on our long-term unsecured debt rating. The holders of the preferred securities have a right to reset the dividend rate on December 20, 2003 and every seven years thereafter. If the new rate is not acceptable to the preferred holders, they have a right to require us to redeem the preferred securities. The preferred holders are also entitled to participating dividends based on refining margins of our Aruba refinery. Coastal Securities may redeem the preferred stock for cash at the liquidation price of $100 million plus accrued and unpaid dividends.

El Paso Oil & Gas Resources Preferred Units. In 1999, El Paso Oil & Gas Resources Company, L.P. (formerly Coastal Oil & Gas Resources, Inc.), our wholly owned subsidiary, issued 50,000 units of preferred units for $50 million to UAGC, Inc., a subsidiary of Rabobank International. The preferred shareholders were entitled to quarterly cash dividends at a rate based on LIBOR. In July 2002, we repurchased the entire 50,000 units for $50 million plus accrued and unpaid dividends.

Coastal Limited Ventures Preferred Stock. In 1999, Coastal Limited Ventures, Inc., our wholly owned subsidiary, issued 150,000 shares of preferred stock for $15 million to JP Morgan Chase Bank (formerly Chase Manhattan Bank). The preferred shareholders were entitled to quarterly cash dividends at an annual rate of 6%. In July 2002, we repurchased the entire 150,000 shares for $15 million plus accrued and unpaid dividends.

Consolidated Partnership. In December 1999, Coastal Limited Ventures contributed assets to a limited partnership in exchange for a controlling general partnership interest. Limited interests in the partnership were issued to RBCC, an unaffiliated investor for $285 million. The limited partners were entitled to a cumulative priority return based on LIBOR. In July 2002, we repurchased the limited partnership interest in El Paso Production Oil & Gas Associates, L.P., formerly known as Coastal Oil and Gas Associates and a partnership formed with Coastal Limited Ventures, Inc. The payment of approximately $285 million to the unaffiliated investor was equal to the sum of the limited partner's outstanding capital plus unpaid priority returns.

Coastal Finance I and Coastal Securities Company Limited are either business trusts we control or companies in which we own all of the voting stock. Consequently, they are consolidated in our financial statements. However, these entities have issued preferred securities, and these preferred interests that are held by various unaffiliated investors are presented in our balance sheet as preferred interests of consolidated subsidiaries. The preferred distributions paid on these preferred interests are presented in our income statement as return on preferred interests of consolidated subsidiaries. Our accounting for some of these preferred interests of consolidated subsidiaries will be impacted by our adoption of the new accounting rules on consolidations in July 2003. For a discussion of the accounting impact, see Note 1 under *New Accounting Pronouncements Issued But Not Yet Adopted.*

16. Commitments and Contingencies

Legal Proceedings

Grynberg. In 1997, a number of our subsidiaries were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value of natural gas produced from royalty properties been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). In May 2001, the court denied the defendants' motions to dismiss. Discovery is proceeding. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). A number of our subsidiaries were named defendants in *Quinque Operating Company, et al v. Gas Pipelines and Their Predecessors, et al*, filed in 1999 in the District Court of Stevens County, Kansas. Quinque has been dropped as a plaintiff and Will Price has been added. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The plaintiff in this case seeks certification of a nationwide class of natural gas working interest owners and natural gas royalty owners to recover royalties that the plaintiff contends these owners should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorney's fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs' motion for class certification has been argued and we are awaiting a ruling. Our costs and legal exposure related to this lawsuit are not currently determinable.

MTBE. In compliance with the 1990 amendments to the Clean Air Act, we use the gasoline additive, methyl tertiary-butyl ether (MTBE), in some of our gasoline. We also produce, buy, sell and distribute MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. We are currently one of several defendants in one such lawsuit in New York. The plaintiffs seek remediation of their groundwater and prevention of future contamination, compensatory damages for the costs of replacement water and for diminished property values, as well as punitive damages, attorney's fees, court costs, and, in some cases, future medical monitoring. Our costs and legal exposure related to this lawsuit and claims are not currently determinable.

Cimarron County. In January of 2003, one of our subsidiaries, CIG Field Services Company (CIG), was named a defendant in a suit titled *Patty Hiner, As Duly Elected County Assessor, The Board of County Commissioners for Cimarron County, Oklahoma v. CIG* in Cimarron County District Court, alleging that in 1999 its agents falsely represented the value of its property to the Cimarron County Property Tax Assessor. The plaintiffs seek compensatory and punitive damages. CIG is in the process of moving the case to the United States District Court for the Western District of Oklahoma for trial. Our costs and legal exposure related to this lawsuit and claims are not currently determinable.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business.

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. As of December 31, 2002, we had approximately $55 million accrued for all outstanding legal matters.

Environmental Matters

We are subject to extensive federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2002, we had accrued approximately $156 million, including approximately $155 million for expected remediation costs at current and former operated sites and associated onsite, offsite and groundwater technical studies, and approximately $1 million for related environmental legal costs, which we anticipate incurring through 2027. Approximately $15 million of the accrual was related to discontinued coal mining operations. The high end of our reserve estimates was approximately $224 million and the low end was approximately $134 million, and our accrual at December 31, 2002 was based on the estimated most likely reasonable amount of liability. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

	December 31, 2002	
Sites	**Low**	**High**
	(In millions)	
Operating	$103	$158
Non-operating	31	65
Superfund	—	1

Below is a reconciliation of our accrued liability as of December 31, 2001 to our accrued liability as of December 31, 2002:

	2002	2001
	(In millions)	
Balance as of January 1	$260	$ 28
Additions/adjustments for remediation activities	14	242
Payments for remediation activities	(23)	(10)
Other changes, net	(95)	—
Balance as of December 31	$156	$260

In addition, we expect to make capital expenditures for environmental matters of approximately $199 million in the aggregate for the years 2003 through 2007. These expenditures primarily relate to compliance with clean air regulations. For 2003, we estimate that our total remediation expenditures will be approximately $23 million. In addition, approximately $16 million of this amount will be expended under government directed clean-up plans. The remaining $7 million will be self-directed or in connection with facility closures.

Coastal Eagle Point. From May 1999 to March 2001, our Coastal Eagle Point Oil Company received several Administrative Orders and Notices of Civil Administrative Penalty Assessment from the New Jersey Department of Environmental Protection (DEP). All of the assessments are related to alleged noncompliance with the New Jersey Air Pollution Control Act pertaining to excess emissions from the first quarter 1998 through the fourth quarter 2000 reported by our Eagle Point refinery in Westville, New Jersey. The DEP has assessed penalties totaling approximately $1.3 million for these alleged violations. The DEP has indicated a willingness to accept a reduced penalty and a supplemental environmental project. Our Eagle Point refinery has been granted an administrative hearing on issues raised by the assessments. Under its global refinery enforcement initiative, the Environmental Protection Agency (EPA) referred several Clean Air Act issues to the DEP. Our Eagle Point refinery expects to resolve these issues along with the DEP assessments. On February 24, 2003, EPA Region 2 issued a Compliance Order based on a 1999 EPA inspection of the refinery's leak detection and repair program. Alleged violations include failure to monitor all components, and failure to timely repair leaking components. During an August 2000 follow-up inspection, the EPA confirmed our Eagle Point refinery had improved implementation of the program. The Compliance Order requires documentation of compliance with the program. Our Eagle Point refinery has requested a conference with the EPA to discuss the Order and the alleged violations. The EPA may seek a monetary penalty.

CERCLA Matters. We have received notice that we could be designated, or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 27 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third parties and settlements which provide for payment of our allocable share of remediation costs. As of December 31, 2002, we have estimated our share of the remediation costs at these sites to be between $5 million and $8 million. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in determining our estimated liabilities.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current reserves are adequate.

Rates and Regulatory Matters

Rate Case. In March 2001, CIG filed a rate case with the Federal Energy Regulatory Commission (FERC) proposing increased rates of $9 million annually and new and enhanced services for its customers. In April 2001, CIG received an order from the FERC, which suspended the rates subject to refund, and subject to the outcome of hearing. On September 26, 2001, the FERC approved certain of its new or enhanced services but rejected two firm services proposed in CIG's rate filing and required it to reallocate the costs allocated to those two services to existing services. CIG complied with this order and arranged with the affected customers to provide service under existing rate schedules. CIG and its customers entered into a settlement agreement in May 2002 settling all issues in the case. The settlement, which contained a small rate increase, was approved by the FERC, and became final in September 2002. The settlement obligates CIG to file a new rate case to be effective no later than October 1, 2006. CIG paid approximately $8 million, including interest, in customer refunds in November 2002. These refunds were included in accrued liabilities, and will not have an adverse effect on our financial position or results of operations. On March 13, 2003, the FERC issued an order approving CIG's refund report.

Marketing Affiliate NOPR. In September 2001, the FERC issued a Notice of Proposed Rulemaking (NOPR). The NOPR proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. The proposed regulations, if adopted by the FERC, would dictate how all our energy affiliates conduct business and interact with our interstate pipelines. In December 2001, we filed comments with the FERC addressing our concerns with the proposed rules. A public hearing was held on May 21, 2002, providing an opportunity to comment further on the NOPR. Following the conference, additional comments were filed by our pipeline subsidiaries and others. At this time, we cannot predict the outcome of the NOPR, but adoption of the regulations in their proposed form would, at a minimum, place additional administrative and operational burdens on us.

Negotiated Rate NOI. In July 2002, the FERC issued a Notice of Inquiry (NOI) that seeks comments regarding its 1996 policy of permitting pipelines to enter into negotiated rate transactions. Our pipelines have entered into these transactions over the years, and the FERC is now reviewing whether negotiated rates should be capped, whether or not the "recourse rate" (a cost-of-service based rate) continues to safeguard against a pipeline exercising market power and other issues related to negotiated rate programs. On September 25, 2002, our pipelines and others filed comments. Reply comments were filed on October 25, 2002. At this time, we cannot predict the outcome of this NOI.

Cash Management NOPR. On August 1, 2002, the FERC issued a NOPR requiring that all cash management or money pool arrangements between a FERC regulated subsidiary and a non-FERC regulated parent must be in writing, and set forth the duties and responsibilities of cash management participants and administrators; the methods of calculating interest and for allocating interest income and expenses; and the restrictions on deposits or borrowings by money pool members. The NOPR also requires specified documentation for all deposits into, borrowings from, interest income from, and interest expenses related to, these arrangements. Finally, the NOPR proposed that as a condition of participating in a cash management or money pool arrangement, the FERC regulated entity maintain a minimum proprietary capital balance of 30 percent, and the FERC regulated entity and its parent maintain investment grade credit ratings. On August 28, 2002, comments were filed. The FERC held a public conference on September 25, 2002, to discuss the issues raised in the comments. Representatives of companies from the gas and electric industries participated on a panel and uniformly agreed that the proposed regulations should be revised substantially and that the proposed capital balance and investment grade credit rating requirements would be excessive. At this time, we cannot predict the outcome of this NOPR.

Also on August 1, 2002, the FERC's Chief Accountant issued an Accounting Release, to be effective immediately. The Accounting Release provides guidance on how companies should account for money pool arrangements and the types of documentation that should be maintained for these arrangements. However, it did not address the proposed requirements that the FERC regulated entity maintain a minimum proprietary capital balance of 30 percent and that the entity and its parent have investment grade credit ratings. Requests for rehearing were filed on August 30, 2002. The FERC has not yet acted on the rehearing requests.

Emergency Reconstruction of Interstate Natural Gas Facilities NOPR. On January 17, 2003, FERC issued a NOPR proposing to (1) expand the scope of construction activities authorized under a pipeline's blanket certificate to allow replacement of mainline facilities; (2) authorize a pipeline to commence reconstruction of the affected system without a waiting period; and (3) authorize automatic approval of construction that would be above the normal cost ceiling. Comments on the NOPR were filed on February 27, 2003. At this time, we cannot predict the outcome of this rulemaking.

Pipeline Safety Notice of Proposed Rulemaking. On January 28, 2003, the U.S. Department of Transportation issued a NOPR proposing to establish a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the notice refers to as "high consequence areas." The proposed rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002, a new bill signed into law in December 2002. We intend to submit comments on the NOPR, which are due on or before April 30, 2003. At this time, we cannot predict the outcome of this rulemaking.

FERC Inquiry. On February 26, 2003, El Paso received a letter from the Office of the Chief Accountant at the FERC requesting details of its announcement of 2003 asset sales and plans for us and our pipeline affiliates to issue a combined $700 million of long-term notes. The letter requested that El Paso explain how it intended to use the proceeds from the issuance of the notes and if the notes will be included in the two regulated companies' capital structure for rate-setting purposes. Our response to the FERC was filed on March 12, 2003, and we fully responded to the request.

While the outcome of our outstanding legal matters, environmental matters, and rates and regulatory matters cannot be predicted with certainty, based on current information and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, operating results or cash flows. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters. It is also possible that these matters could impact our debt rating and credit rating. Further, for environmental matters, it is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As new information regarding our outstanding legal matters, environmental matters and rates and regulatory matters becomes available, or relevant developments occur, we will review our accruals and make any appropriate adjustments. The impact of these changes may have a material effect on our results of operations, our financial position, and on our cash flows in the period the event occurs.

Capital Commitments and Purchase Obligations

At December 31, 2002, we had capital and investment commitments of $98 million primarily relating to our Production, Pipeline and Merchant Energy activities, which include obligations for natural gas purchases, transportation and storage capacity, maintenance and capital investments. Our other planned capital and investment projects are discretionary in nature, with no substantial capital commitments made in advance of the actual expenditures. Our pipelines have entered into unconditional purchase obligations for products and services totaling $235 million at December 31, 2002. Our annual obligations under these agreements are $23 million for each of the years 2003 through 2007, and $120 million in total thereafter.

Operating Leases

We maintain operating leases in the ordinary course of our business activities. These leases include those for office space and operating facilities and office and operating equipment, and the terms of the agreements vary from 2002 until 2031. As of December 31, 2002, our total commitments under operating leases were approximately $397 million.

Under one of our leases, we have provided a residual value guarantee to the lessor. For the total outstanding residual value guarantee on our Aruba operating lease at December 31, 2002, see *Residual Value Guarantees* below.

Minimum annual rental commitments at December 31, 2002, were as follows:[1]

Year Ending December 31,	Operating Leases (In millions)
2003	$103
2004	78
2005	46
2006	33
2007	23
Thereafter	114
Total	$397

(1) These amounts exclude minimum annual rental commitments paid by our parent, which are allocated to us through an overhead allocation.

Rental expense for the years ended December 31, 2002, 2001 and 2000 was $136 million, $92 million and $140 million.

Letters of Credit

We enter into letters of credit in the ordinary course of our operating activities. As of December 31, 2002, we had no outstanding letters of credit related to the marketing and trading activities, and $51 million related to the domestic power development and other operating activities.

Guarantees

We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. For example, if the guaranteed party is required to deliver natural gas to a third party and then fails to do so, we would be required to either deliver that natural gas or make payments to the third party equal to the difference between the contract price and the market value of the natural gas.

As of December 31, 2002, we had approximately $50 million of guarantees in connection with our international development and operating activities not consolidated on our balance sheet and approximately $11 million of guarantees in connection with our domestic development and operating activities not consolidated on our balance sheet.

Residual Value Guarantees

Under one of our operating leases, we have provided a residual value guarantee to the lessor. Under this guarantee, we can either choose to purchase the asset at the end of the lease term for a specified amount, which is equal to the outstanding loan amount owed by the lessor, or we can choose to assist in the sale of the leased asset to a third party. Should the asset not be sold for a price that equals or exceeds the amount of the guarantee, we would be obligated for the shortfall. The level of our residual value guarantee is 89.9 percent of the original cost of the leased assets. Accounting for this residual value guarantee will be impacted effective July 1, 2003 by our adoption of the new accounting rules on consolidations. For a discussion of the accounting impact of these new rules, see Note 1.

As of December 31, 2002, we had purchase options and residual value guarantees associated with operating lease for the following asset:

Asset Description	Purchase Option	Residual Value Guarantee	Lease Expiration
		(In millions)	
Facility at Aruba refinery	$370	$333	2006

17. Retirement Benefits

Pension and Retirement Benefits

El Paso maintains a pension plan to provide benefits as determined by a cash balance formula covering substantially all of its U.S. employees, including our employees except for employees of our coal and retail operations who are covered under separate plans. El Paso also maintains a defined contribution plan covering its U.S. employees, including our employees. Prior to May 1, 2002, El Paso matched 75 percent of participant basic contributions up to 6 percent, with the matching contribution being made to the plan's stock fund, which participants could diversify at any time. After May 1, 2002, the plan was amended to allow for company matching contributions to be invested in the same manner as that of participant contributions. Effective March 1, 2003, El Paso suspended the matching contribution. El Paso is responsible for benefits accrued under its plan and allocates the related costs to its affiliates.

Prior to our merger with El Paso, we maintained both defined benefit and defined contribution plans. Our pension plans covered substantially all of our U.S. employees. On April 1, 2001, our primary pension plan was merged into El Paso's existing cash balance plan. Our employees who were participants in our primary plan on March 31, 2001 receive the greater of cash balance benefits or our plan benefits accrued through March 31, 2006. Effective September 30, 2002, the Coastal Mart pension plan was frozen. Effective March 17, 2003, the Coastal Coal pension plan was frozen. In addition, we maintained a defined contribution plan. Under this plan, we matched 100 percent of basic contributions of up to 8 percent with matching contributions made in our common stock. On January 29, 2001, this plan was merged into El Paso defined Contribution plan.

Other Postretirement Benefits

As a result of our merger with El Paso, El Paso offered a one-time election through an early retirement window for employees who were at least age 50 with 10 years of service on December 31, 2000, to retire on or before June 30, 2001, and keep benefits under our postretirement medical and life plans. Total charges associated with the curtailment and special termination benefits were $65 million. Medical benefits for this closed group of retirees may be subject to deductibles, co-payment provisions and other limitations and dollar caps on the amount of employer costs. El Paso has reserved the right to change these benefits. Employees who retire on or after June 30, 2001, will continue to receive limited postretirement life insurance benefits. Our postretirement benefit plan costs are pre-funded to the extent such costs are recoverable through rates.

In January 2001, following the merger, we changed the measurement date for measuring our pension and other postretirement benefit obligations from December 31 to September 30. We made this change to conform our measurement date to the date El Paso uses to measure pension and other postretirement benefit obligations. The new method is consistent with the manner in which El Paso gathers pension and other postretirement benefit information and will facilitate ease of planning and reporting in a more timely manner. We believe this method is preferable to the method previously employed. We accounted for this as a change in accounting principle, and it had no material effect on retirement benefit expense for the current or prior periods.

Due to a Corporate-wide restructuring during 2002, Coastal Mart is no longer part of us. As a result, the 2002 pension benefits shown below only reflect our Coal benefits, while the year-end 2001 pension benefits reflect both our Coastal Mart and our Coal pension benefits. The following table sets forth the change in benefit obligation, change in plan assets, reconciliation of funded status and components of net periodic benefit cost for pension benefits and other postretirement benefits for the twelve months ended September 30.

	Pension Benefits		Postretirement Benefits	
	2002	2001	2002	2001
	(In millions)			
Change in benefit obligation				
Benefit obligation at beginning of period	$ 84	$ 822	$109	$114
Service cost	3	5	1	1
Interest cost	5	20	8	9
Participant contributions	—	—	4	3
Plan amendment	—	—	—	(12)
Curtailment and special termination benefit	—	137	—	16
Actuarial loss (gain)	10	75	(5)	(15)
Benefits paid	(3)	(13)	(15)	(7)
Transfer of plan obligations	(20)	(962)	—	—
Benefit obligation at end of period	$ 79	$ 84	$102	$109
Change in plan assets				
Fair value of plan assets at beginning of period	$ 97	$ 1,971	$ 40	$ 35
Actual return on plan assets	(8)	(182)	(1)	1
Employer contributions	—	—	18	8
Participant contributions	—	—	4	3
Benefits paid	(3)	(13)	(15)	(7)
Transfer of plan assets	(27)	(1,679)	—	—
Fair value of plan assets at end of period	$ 59	$ 97	46	$ 40
Reconciliation of funded status				
Funded status at end of period	$(20)	$ 13	$(56)	$(69)
Fourth quarter contributions	—	—	4	4
Unrecognized net actuarial loss (gain)	28	14	(29)	(29)
Unrecognized prior services costs	1	—	—	—
Other	—	1	—	—
Prepaid (accrued) benefit cost at December 31,	$ 9	$ 28	$(81)	$(94)
Amounts recognized in the statement of financial position consist of:				
Prepaid benefit cost	$ —	$ 28		
Accrued benefit liability	(11)	—		
Intangible asset	1	—		
Accumulated other comprehensive income	19	—		
Net amount recognized at year-end	$ 9	$ 28		
Other comprehensive income attributable to change in additional minimum liability recognition	$ 19	$ —		

Included in the above information is the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets for the pension plan with accumulated benefit obligations in excess of plan assets of $79 million, $70 million, and $59 million as of December 31, 2002.

	Pension Benefits			Postretirement Benefits		
	Year Ended December 31,					
	2002	2001	2000	2002	2001	2000
	(In millions)					
Benefit cost for the plans includes the following components						
Service cost	$ 3	$ 5	$ 21	$ 1	$ 1	$ 3
Interest cost	5	20	59	8	9	8
Expected return on plan assets	(7)	(55)	(164)	(2)	(2)	(1)
Amortization of net actuarial gain	—	(9)	(20)	(1)	—	(2)
Amortization of transition obligation	—	(2)	(8)	—	—	6
Amortization of prior service cost	—	—	1	—	—	1
Curtailment and special termination benefit	—	137	—	—	65	—
Net benefit cost (income)	$ 1	$ 96	$(111)	$ 6	$73	$15

Benefit obligations are based upon actuarial estimates as described below:

	Pension Benefits		Postretirement Benefits	
	2002	2001	2002	2001
Weighted average assumptions				
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected return on plan assets	8.80%	10.00%	7.50%	7.50%
Rate of compensation increase	4.00%	4.00%	—	—

Actuarial estimates for our postretirement benefits plans assumed a weighted average annual rate of increase in the per capita costs for covered health care benefits of 11.0 percent in 2002, gradually decreasing to 5.5 percent by the year 2008. Assumed health care cost trends have a significant effect on the amounts reported for other postretirement benefit plans. A one-percentage point change from assumed health care cost trends would have the following effects:

	2002	2001
	(In millions)	
One Percentage Point Increase		
Aggregate of service cost and interest cost	$ —	$ —
Accumulated postretirement benefit obligation	$ 2	$ 3
One Percentage Point Decrease		
Aggregate of service cost and interest cost	$ —	$ —
Accumulated postretirement benefit obligation	$ (2)	$ (3)

18. Segment Information

We segregate our business activities into four distinct operating segments: Pipelines, Production, Field Services and Merchant Energy. These segments are strategic business units that provide a variety of energy products and services. They are managed separately as each business unit requires different technology and marketing strategies. In the second quarter of 2002, we reclassified our historical coal mining operations from our Merchant Energy segment to discontinued operations in our financial statements. All periods were restated to reflect this change.

Our Pipelines segment provides natural gas transmission, storage, gathering and related services in the U.S. and internationally. We conduct our activities primarily through three wholly owned and two partially owned interstate transmission systems along with five underground natural gas storage entities. Our pipeline operations also include access between our U.S. based systems and Canada.

Our Production segment is engaged in the exploration for, and the acquisition, development and production of natural gas, oil and natural gas liquids, primarily in North America. In the U.S., Production has onshore and coal seam operations and properties in 10 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary and Indonesia.

Our Field Services segment provides customers with wellhead-to-mainline services, including natural gas gathering, products extraction, fractionation, dehydration, purification, compression and transportation of natural gas and natural gas liquids. Field Services' assets are located in the south Texas, south Louisiana, Mid-Continent and Rocky Mountain regions.

Our Merchant Energy segment consists of two primary divisions: global power and petroleum. We buy, sell and trade natural gas, power, crude oil, refined products, coal and other energy commodities throughout the world, and own or have interests in 19 power plants in 8 countries.

We use EBIT to assess the operating results and effectiveness of our business segments. We define EBIT as operating income, adjusted for several items, including: earnings from unconsolidated affiliates, minority interests on consolidated, but less than wholly-owned operating subsidiaries and other miscellaneous non-operating items. Items that are not included in this measure are financing costs, including interest and debt expense and returns on preferred interests of consolidated subsidiaries, income taxes, discontinued operations, extraordinary items and the impact of accounting changes. We believe this measurement is useful to our investors because it allows them to evaluate the effectiveness of our businesses and operations and our investments from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures such as operating cash flow. The following are our segment results as of and for the years ended December 31:

	Segments As of or for the Year Ended December 31, 2002					
	Pipelines	Production	Field Services	Merchant Energy	Other[1]	Total
	(In millions)					
Revenues from external customers						
Domestic	$ 893	$1,092	$ 404	$5,054[2]	$ —	$ 7,443
Foreign	3	71	3	1,010[2]	—	1,087
Intersegment revenue	30	95	53	(147)[2]	(31)	—
Restructuring costs	—	—	—	5	—	5
(Gain) loss on long-lived assets	(12)	708	(21)	114	2	791
Ceiling test charges	—	245	—	—	—	245
Depreciation, depletion and amortization	116	446	14	92	13	681
Operating income (loss)	$ 419	$ (461)	$ 67	$ 150	$ (39)	$ 136
Earnings (loss) from unconsolidated affiliates	105	4	(54)	49	—	104
Minority interests in consolidated subsidiaries	—	—	—	(52)	—	(52)
Other income	16	1	1	72	28	118
Other expense	(3)	—	(1)	(26)	(7)	(37)
EBIT	$ 537	$ (456)	$ 13	$ 193	$ (18)	$ 269
Discontinued operations, net of income taxes	$ —	$ —	$ —	$ —	$(124)	$ (124)
Cumulative effect of accounting changes, net of income taxes	—	—	—	14	—	14
Assets						
Domestic	5,116	3,750	403	4,339	585[3]	14,193
Foreign	59	620	14	2,146	201	3,040
Capital expenditures and investments in unconsolidated affiliates	252	1,124	20	281	98	1,775
Total investments in unconsolidated affiliates	404	114	97	912	17	1,544

(1) Includes our Corporate and eliminations of intercompany transactions, our retail business. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Other" column, to remove intersegment transactions.

(2) Merchant Energy revenues take into account the adoption of a consensus reached on EITF Issue No. 02-3, which requires us to report all physical sales of energy commodities in our energy trading activities on a net basis as a component of revenues. See Note 1 regarding the adoption of this Issue.

(3) Includes $106 million of assets that are classified as discontinued operations.

	Segments As of or for the Year Ended December 31, 2001					
	Pipelines	Production	Field Services	Merchant Energy	Other[(1)]	Total
	(In millions)					
Revenues from external customers						
Domestic	$ 982	$1,772	$822	$4,077[(2)]	$ 355	$ 8,008
Foreign	2	46	4	664[(2)]	—	716
Intersegment revenue	70	(35)	68	199[(2)]	(302)	—
Merger-related costs	192	45	13	44	520	814
Loss on long-lived assets	22	16	—	127	10	175
Ceiling test charges	—	115	—	—	—	115
Depreciation, depletion and amortization	137	453	15	72	21	698
Operating income (loss)	$ 195	$ 785	$ 55	$ (263)	$ (714)	$ 58
Earnings from unconsolidated affiliates	98	4	16	115	—	233
Other income	8	3	—	159	20	190
Other expense	(9)	(1)	—	(14)	(4)	(28)
EBIT	$ 292	$ 791	$ 71	$ (3)	$ (698)	$ 453
Discontinued operations, net of income taxes	$ —	$ —	$ —	$ —	$ (5)	$ (5)
Extraordinary items, net of income taxes	—	—	(4)	(7)	—	(11)
Assets						
Domestic	5,347	5,761	529	2,493	669[(3)]	14,799
Foreign	14	773	17	3,431	32	4,267
Capital expenditures and investments in unconsolidated affiliates	421	1,814	53	142	136	2,566
Total investments in unconsolidated affiliates	547	110	168	1,041	16	1,882

(1) Includes our Corporate and eliminations of intercompany transactions, our retail business. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Other" column, to remove intersegment transactions.

(2) Merchant Energy revenues take into account the adoption of a consensus reached on EITF Issue No. 02-3, which requires us to report all physical sales of energy commodities in our energy trading activities on a net basis as a component of revenues. See Note 1 regarding the adoption of this Issue.

(3) Includes $352 million of assets that are classified as discontinued operations.

	Segments As of or for the Year Ended December 31, 2000					
	Pipelines	Production	Field Services	Merchant Energy	Other[1]	Total
	(In millions)					
Revenues from external customers						
Domestic	$ 972	$ 806	$709	$9,957[2]	$1,191	$13,635
Foreign	—	5	2	1,974[2]	—	1,981
Intersegment revenue	73	320	44	336[2]	(773)	—
Merger-related costs	—	—	—	—	13	13
(Gain) loss on long-lived assets	1	—	(3)	(4)	1	(5)
Depreciation, depletion and amortization	132	399	8	73	30	642
Operating income	$ 387	$ 417	$ 89	$ 137	$ 43	$ 1,073
Earnings from unconsolidated affiliates	97	—	23	160	1	281
Other income	16	1	—	74	35	126
Other expense	—	(5)	(1)	(3)	(1)	(10)
EBIT	$ 500	$ 413	$111	$ 368	$ 78	$ 1,470
Discontinued operations, net of income taxes	$ —	$ —	$ —	$ (1)	$ —	$ (1)
Assets						
Domestic	5,182	4,038	512	4,922	1,780[3]	16,434
Foreign	83	198	17	2,086	57	2,441
Capital expenditures and investments in unconsolidated affiliates	232	1,583	45	446	23	2,329
Total investments in unconsolidated affiliates	609	—	193	794	17	1,613

(1) Includes our Corporate and eliminations of intercompany transactions, our retail business. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Other" column, to remove intersegment transactions.

(2) Merchant Energy revenues take into account the adoption of a consensus reached on EITF Issue No. 02-3, which requires us to report all physical sales of energy commodities in our energy trading activities on a net basis as a component of revenues. See Note 1 regarding the adoption of this Issue.

(3) Includes $322 million of assets that are classified as discontinued operations.

The reconciliations of EBIT to income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes are presented below for each of the three years ended December 31:

	2002	2001	2000
	(In millions)		
Total EBIT for segments	$ 269	$ 453	$1,470
Interest and debt expense	(433)	(447)	(502)
Affiliated interest expense, net	(9)	(46)	—
Returns on preferred interests of consolidated subsidiaries	(35)	(51)	(60)
Income taxes	35	(81)	(253)
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$(173)	$(172)	$ 655

We had no customers whose revenues exceeded 10 percent of our total revenues in 2002, 2001 and 2000.

19. Supplemental Cash Flow Information

The following table contains supplemental cash flow information for the years ended December 31:

	2002	2001	2000
	(In millions)		
Interest paid	$ 517	$589	$389
Income tax payments (refunds)	(1)	77	70

20. Investments in and Advances to Unconsolidated Affiliates and Transactions with Related Parties

We hold investments in various unconsolidated affiliates which are accounted for using the equity method of accounting. Our principal equity method investees are international pipelines, interstate pipelines, power generation plants and gathering systems. Our investment balance was greater than our equity in the net assets of these investments as of December 31, 2002 and 2001 by $39 million and $79 million. In 2002, the primary differences related to unamortized purchase price adjustments and deferred taxes recorded on FERC regulated equity investments. In 2001, the primary differences related to unamortized purchase price adjustments and deferred taxes recorded on FERC regulated equity investments. Our net ownership interest, investments in and advances to our unconsolidated affiliates are as follows as of December 31:

	Country	Type of Entities	Net Ownership Interest	Investments 2002	Investments 2001	Advances 2002	Advances 2001
				(In millions)			
United States							
Alliance Pipeline Limited Partnership[1]		LP[2]	2%	$ 24	$ 160	$ —	$—
Aux Sable Liquid[3]		LP[2]	14%	—	58	—	—
Bastrop Company, LLC		LLC[4]	50%	121	99	—	—
Eagle Point Cogeneration Partnership[5]		GP[6]	84%	—	85	—	—
Great Lakes Gas Transmission[7]			50%	312	297	—	—
Midland Cogeneration Venture		LP[2]	44%	316	276	—	—
Noric Holdings I, LLC[8]		LLC[4]	42%	114	110	—	—
Other Domestic Investments[9]			various	243	345	21	—
Total United States				1,130	1,430	21	—
Foreign							
EGE Fortuna	Panama	Corporation	25%	61	56	—	—
EGE Itabo	Dominican Republic	Corporation	25%	87	101	—	—
Habibullah Power	Pakistan	LLC[4]	50%	57	53	99	—
Saba Power Company	Pakistan	LLC[4]	94%	55	48	—	—
Other Foreign Investments[9]			various	154	194	73	59
Total Foreign				414	452	172	59
Total investments in and advances to unconsolidated affiliates				$1,544	$1,882	$193	$59

(1) We sold 12.3 percent interest in November 2002, and we sold the remaining of 2.1 percent interest in March 2003.
(2) LP represents Limited Partnership.
(3) We sold 100 percent of our interest in November 2002.
(4) LLC represents Limited Liability Company.
(5) Consolidated in January 2002.
(6) GP represents General Partnership.
(7) Includes a 46 percent general partner interest in Great Lakes Gas Transmission Limited Partnership and a 4 percent limited partner interest through our ownership in Great Lakes Gas Transmission Company.
(8) In June 2001, we conveyed natural gas and oil properties to an affiliate for an equity investment of 26 percent. In December 2001, we conveyed additional properties which increased our ownership percentage to 42 percent.
(9) Denotes investments less than $50 million.

Earnings from our unconsolidated affiliates, including parent level adjustments on these investees, asset impairments and realized gains or losses on the sale of equity investments are as follows for the years ended December 31:

	2002	2001	2000
		(In millions)	
Alliance Pipeline Limited Partnership[1]	$ 21	$ 23	$ 12
Aux Sable Liquid	(3)	(4)	(2)
Bastrop Company, LLC	(5)	—	—
Eagle Point Cogeneration Partnership[2]	—	22	25
EGE Itabo	(2)	5	9
Great Lakes Gas Transmission	63	55	52
Habibullah Power	10	2	9
Midland Cogeneration Venture	28	23	37
Noric Holdings I, LLC	4	4	—
Saba Power Company	7	—	1
Other	32	93	122
	155	223	265
Impairment charges and gains and losses on sales of investments	(51)	10	16
Total earnings from unconsolidated affiliates	$104	$233	$281

(1) We sold 12.3 percent interest in November 2002, and we sold the remaining of 2.1 percent interest in March 2003.
(2) Consolidated in January 2002.

Our impairment charges and gains and losses on sales of our investments during 2002, 2001 and 2000 were as follows:

Investment	Pre-tax Gain (Loss)	Cause of Impairments or Gain (Loss)
	(In millions)	
2002		
Aux Sable	$ (47)	Impairment generated as a result of the sale of investment
Other	(4)	
	$ (51)	
2001		
Deepwater Investors	$ 13	Sale of investment to El Paso Energy Partners
Other	(3)	
	$ 10	
2000		
Guatemala Power	$ 16	Sale of investment
	$ 16	

As discussed in Note 2, we have divested our ownership interest in the Empire State, Iroquois, Stingray and U-T offshore pipeline systems in 2001.

Summarized financial information of our proportionate share of unconsolidated affiliates below includes affiliates in which we hold a less than 50 percent interest as well as those in which we hold a greater than 50 percent interest. Our proportional shares of the unconsolidated affiliates in which we hold a greater than 50 percent interest had net income of $23 million and $38 million for December 31, 2002 and 2001 and total assets of $443 million and $760 million for December 31, 2002 and 2001.

	Year Ended December 31,		
	2002	2001	2000
		(Unaudited) (In millions)	
Operating results data:			
Operating revenues	$1,194	$1,303	$4,103
Operating expenses	928	959	3,837
Income from continuing operations	129	200	247
Net income	152	200	247

	December 31,	
	2002	2001
	(Unaudited) (In millions)	
Financial position data:		
Current assets	$ 609	$ 576
Non-current assets	2,635	3,508
Short-term debt	244	228
Other current liabilities	241	249
Long-term debt	1,084	1,524
Other non-current liabilities	170	279
Equity in net assets	1,505	1,804

We have a 43.5 percent ownership interest, which consists of a 38.1 percent general partner and a 5.4 percent limited partner interest in Midland Cogeneration Venture Limited Partnership, a Michigan limited partnership that qualifies as a significant subsidiary to the parent El Paso CGP Company. Although we own a percentage of the general partner interest, we do not serve as the operating partner. We participate in the decisions at the partnership but do not have a controlling interest. Midland Cogeneration develops, owns and operates a combined-cycle, gas-fired cogeneration facility in Midland.

Summarized financial information of our proportionate share of Midland Cogeneration Venture LP is as follows:

	Year Ended December 31,		
	2002	2001	2000
		(Unaudited) (In millions)	
Operating Results Data:			
Operating revenues	$260	$266	$263
Operating expenses	178	197	170
Income from continuing operations	32	21	39
Net income	57	21	39

	As of December 31, 2002	As of December 31, 2001
	(Unaudited) (In millions)	
Financial Position Data:		
Current assets	$155	$149
Non-current assets	758	772
Short-term debt	41	81
Other current liabilities	50	58
Long-term debt	502	541
Other non-current liabilities	1	1
Equity in net assets	319	240

The following table shows revenues and charges from our unconsolidated affiliates and El Paso's subsidiaries:

	2002	2001	2000
		(In millions)	
Revenues	$1,551	$2,090	$1,427
Cost of sales	278	194	317
Reimbursement for operating expenses	3	11	11
Charges from affiliates	341	335	—
Other income	6	8	7

We enter into transactions with other El Paso subsidiaries and unconsolidated affiliates in the ordinary course of business to transport, sell and purchase natural gas and various contractual agreements for trading activities. Prior to October 2000, we had significant activities with Engage Energy. During the fourth quarter of 2000, we terminated the Engage joint venture and assumed the U.S. portion of Engage. In February 2001, we transferred our natural gas and power trading activities to El Paso Merchant Energy, an affiliate and subsidiary of El Paso, in exchange for a 22 percent interest in El Paso Merchant Energy, L.P. The transfer was based on estimated fair value of contracts transferred, and the investment was accounted for on a cost basis. In September 2001, we redeemed this interest. As a result, operational related party transactions that had previously been with an unconsolidated affiliate are now with an affiliate. For the period ended 2002 and 2001, we recognized revenues with El Paso Merchant Energy of $1,124 million and $1,554 million which were primarily with our Production segment. We had cost of sales of $198 million and $111 million with El Paso Merchant Energy for 2002 and 2001. In addition, other operational affiliated transactions have increased due to the El Paso merger.

El Paso has allocated a portion of its general and administrative expenses to us since 2001. The allocation is based on the estimated level of effort devoted to our operations and the relative size of our EBIT, gross property and payroll. For the years ended December 2002 and 2001, the annual charges were $146 million and $193 million. During 2002 and 2001, El Paso Natural Gas Company and Tennessee Gas Pipeline Company allocated payroll and other expenses to us associated with our shared pipeline services. The allocated expenses are based on the estimated level of staff and their expenses to provide the services. For the years ended December 2002 and 2001, the annual charges were $40 million and $34 million. El Paso also provides our production segment administrative and other shared production services and allocated $155 million and $102 million in 2002 and 2001. We believe the allocation methods are reasonable.

Related Party Transactions

In March 2002, we acquired assets with a net book value, net of deferred taxes, of approximately $8 million from El Paso.

Additionally, we sold natural gas and oil properties to El Paso. Net proceeds from these sales were $404 million, and we did not recognize a gain or loss on the properties sold. The proceeds exceeded the net book value by $32 million and we recorded this proceeds as an increase to paid in capital.

In November 2002, we sold our stock in Coastal Mart Inc., one of our wholly owned subsidiaries to El Paso Remediation Company, a wholly owned subsidiary of El Paso Corporation. We recorded a receivable of $42 million, which was based on the book value of the company (since the sale occurred between entities under common control). We did not recognize a gain or loss on this sale.

We participate in El Paso's cash management program which matches short-term cash surpluses and needs of its participating affiliates, thus minimizing total borrowing from outside sources. As of December 31, 2002 and December 31, 2001, we had borrowed $2,374 million and $908 million. The market rate of interest as of December 31, 2002 was 1.5% and at December 31, 2001, it was 2.1%. In addition, we had a demand note receivable with El Paso of $199 million at December 31, 2002, at an interest rate of 2.2%. At December 31, 2001, the demand note receivable was $120 million at an interest rate of 4.2%.

At December 31, 2002 and December 31, 2001, we had accounts and notes receivable from related parties of $346 million and $449 million. In addition, we had a non-current note receivable from a related party of $126 million and $27 million included in other non-current assets at December 31, 2002 and at December 31, 2001.

At December 31, 2002 and December 31, 2001, we had other accounts payable to related parties of $87 million and $428 million. In addition, included in short-term borrowings at December 31, 2001, was a current note payable to related parties of $67 million.

21. Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below:

	Quarters Ended				
	December 31	September 30	June 30	March 31	Total
	(In millions)				
2002[1]					
Operating revenues[2]	$2,377	$1,648	$1,950	$2,555	$8,530
Restructuring costs	5	—	—	—	5
Gain (loss) on long-lived assets	816	(1)	(13)	(11)	791
Ceiling test charges	2	—	233	10	245
Operating income (loss)[3]	(672)	56	32	720	136
Income (loss) from continuing operations before cumulative effect of accounting changes	(531)	(20)	(35)	413	(173)
Discontinued operations, net of income taxes	(2)	(36)	(67)	(19)	(124)
Cumulative effect of accounting changes, net of income taxes	—	—	14	—	14
Net income (loss)	(533)	(56)	(88)	394	(283)
2001[1]					
Operating revenues[4]	$1,562	$1,951	$2,655	$2,556	$8,724
Merger-related costs	(17)	10	203	618	814
Gain (loss) on long-lived assets	9	7	6	153	175
Ceiling test charges	—	115	—	—	115
Operating income (loss)[5]	246	124	(7)	(305)	58
Income (loss) from continuing operations before extraordinary items	192	39	(65)	(338)	(172)
Discontinued operations, net of income taxes	(4)	1	(3)	1	(5)
Extraordinary items, net of income taxes	—	(4)	3	(10)	(11)
Net income (loss)	188	36	(65)	(347)	(188)

[1] Our coal mining operations are classified as discontinued operations. See Note 9 for further discussion.

(2) Our operating revenues differ from those previously reported in our March 31, 2002 Form 10-Q by $2,397 million due to income statement reclassifications associated with our adoption of EITF Issue No. 02-3, discounted operations and other minor reclassifications, which had no impact on previously reported net income or stockholder's equity.

(3) Our operating income (loss) differs from that previously reported in our September 30, 2002, June 30, 2002 and March 31, 2002 Form 10-Q's by $1 million, $12 million and $41 million due to income statement reclassifications associated with our discontinued operations, reclassifications of gains and losses on asset sales and asset impairments to operating income and other minor reclassifications which had no impact on previously reported net income or stockholder's equity.

(4) Our operating revenues differ from those previously reported in our September 30, 2001, June 30, 2001, and March 31, 2001 Form 10-Q's by $4,451 million, $3,211 million and $5,306 million due to income statement reclassifications associated with our adoption of EITF Issue No. 02-3, discounted operations and other minor reclassifications, which had no impact on previously reported net income or stockholder's equity.

(5) Our operating income (loss) differs from that previously reported in our September 30, 2001, June 30, 2001, and March 31, 2001 Form 10-Q's by $2 million, $41 million and $5 million due to income statement reclassifications associated with our discontinued operations, reclassification of gains and losses on asset sales and asset impairments to operating income and other minor reclassifications, which had no impact on previously reported net income or stockholder's equity.

22. Supplemental Natural Gas and Oil Operations (Unaudited)

At December 31, 2002, we had interests in natural gas and oil properties in 10 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have a limited number of natural gas and oil properties in Brazil, Canada, Hungary and Indonesia. We also have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary and Indonesia.

For purposes of the Supplemental Natural Gas and Oil Operations disclosure, we have presented reserves, standardized measure of discounted future net cash flows and the related changes in standardized measure separately for natural gas systems operations which includes the natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries that were sold in 2002. The Supplemental Natural Gas and Oil Operations disclosure does not include any value for storage gas and liquids volumes managed by our Pipelines segment.

Capitalized costs relating to natural gas and oil producing activities and related accumulated depreciation, depletion and amortization were as follows at December 31:

	United States	Canada	Other Countries[1]	Worldwide
		(In millions)		
2002				
Natural gas and oil properties:				
Costs subject to amortization	$6,106	$608	$ 92	$6,806
Costs not subject to amortization	314	177	103	594
	6,420	785	195	7,400
Less accumulated DD&A	3,222	435	44	3,701
Net capitalized costs	$3,198	$350	$151	$3,699
2001				
Natural gas and oil properties:				
Costs subject to amortization	$6,394	$415	$ 72	$6,881
Costs not subject to amortization	494	250	49	793
	6,888	665	121	7,674
Less accumulated DD&A	2,316	170	31	2,517
Net capitalized costs	$4,572	$495	$ 90	$5,157

(1) Includes International operations in Brazil, Hungary and Indonesia.

Costs incurred in natural gas and oil producing activities, whether capitalized or expensed, were as follows at December 31:

	United States	Canada	Other Countries[1]	Worldwide
		(In millions)		
2002				
Property acquisition costs				
Proved properties	$ 23	$ 6	$—	$ 29
Unproved properties	12	7	10	29
Exploration costs	49	70	45	164
Development costs	717	80	3	800
Total costs incurred	$ 801	$163	$58	$1,022
2001				
Property acquisition costs				
Proved properties	$ 87	$232	$—	$ 319
Unproved properties	33	16	25	74
Exploration costs	110	19	58	187
Development costs	1,026	105	14	1,145
Total costs incurred	$1,256	$372	$97	$1,725
2000				
Property acquisition costs				
Proved properties	$ 127	$ 3	$—	$ 130
Unproved properties	130	6	—	136
Exploration costs	193	42	11	246
Development costs	960	69	—	1,029
Total costs incurred	$1,410	$120	$11	$1,541

[1] Includes International operations in Brazil, Hungary and Indonesia.

In our January 1, 2003 reserve report, the amounts estimated to be spent in 2003, 2004 and 2005 to develop our worldwide booked proved undeveloped reserves are $323 million, $282 million and $88 million.

Presented below is an analysis of the capitalized costs of natural gas and oil properties by year of expenditure that are not being amortized as of December 31, 2002, pending determination of proved reserves. Capitalized interest of $13 million, $17 million, and $7 million for the years ended December 31, 2002, 2001 and 2000 is included in the presentation below (in millions):

	Cumulative Balance December 31,	Costs Excluded for Years Ended December 31,			Cumulative Balance December 31,
	2002	2002	2001	2000	1999
Worldwide[1]					
Acquisition	$296	$ 47	$131	$ 66	$ 52
Exploration	144	97	15	27	5
Development	154	10	95	26	23
	$594	$154	$241	$119	$ 80

[1] Includes operations in the United States, Brazil, Canada, Hungary and Indonesia.

Projects presently excluded from amortization are in various stages of evaluation. The majority of these costs are expected to be included in the amortization calculation in the years 2003 through 2006. Total amortization expense per Mcfe, including ceiling test charges, was $2.20, $1.29, and $1.05 in 2002, 2001, and 2000. Excluding ceiling test charges, amortization expense would have been $1.44 per Mcfe in 2002. Depreciation, depletion, and amortization excludes provisions for the impairment of international projects of $15 million in 2000.

Net quantities of proved developed and undeveloped reserves of natural gas and liquids, including condensate and crude oil, and changes in these reserves are presented below. Information in this table is based on the reserve report dated January 1, 2003, prepared internally by Production and reviewed by Huddleston & Co., Inc. This information is consistent with estimates of reserves filed with other federal agencies except for differences of less than five percent resulting from actual production, acquisition, property sales, necessary reserve revisions and additions to reflect actual experience. These reserves include 465,783 MMcfe of production delivery commitments under financing arrangements that extend through 2042. The financing arrangement supported by these reserves matures in 2006. Total proved reserves on the fields with this dedicated production were 919,265 MMcfe.

	Natural Gas (in Bcf)				
	United States	Canada	Other Countries[1]	Worldwide	Natural Gas Systems[2]
Net proved developed and undeveloped reserves[3]					
January 1, 2000	3,269	73	—	3,342	198
Revisions of previous estimates	(203)	(62)	—	(265)	11
Extensions, discoveries and other	802	155	91	1,048	—
Purchases of reserves in place	499	2	—	501	—
Sales of reserves in place	(19)	—	—	(19)	—
Production	(328)	(1)	—	(329)	(33)
December 31, 2000	4,020	167	91	4,278	176
Revisions of previous estimates	(996)	(136)	(51)	(1,183)	42
Extensions, discoveries and other	604	85	—	689	—
Purchases of reserves in place	103	83	—	186	—
Sales of reserves in place	—	—	—	—	—
Production	(373)	(13)	—	(386)	(35)
December 31, 2001	3,358	186	40	3,584	183
Revisions of previous estimates	(169)	(70)	31	(208)	—
Extensions, discoveries and other	195	56	5	256	—
Purchases of reserves in place	—	5	—	5	—
Sales of reserves in place	(1,569)	(30)	—	(1,599)	(183)
Production	(247)	(17)	—	(264)	—
December 31, 2002	1,568	130	76	1,774	—
Proved developed reserves					
December 31, 2000	1,816	112	—	1,928	176
December 31, 2001	1,613	138	—	1,751	183
December 31, 2002	969	104	—	1,073	—

(1) Includes International operations in Brazil, Hungary and Indonesia.

(2) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries that were sold in 2002.

(3) Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.

	Liquids[1] (in MBbls)				
	United States	Canada	Other Countries[2]	Worldwide	Natural Gas Systems[3]
Net proved developed and undeveloped reserves[4]					
January 1, 2000	56,878	867	—	57,745	249
Revisions of previous estimates	238	(544)	—	(306)	7
Extensions, discoveries and other	8,231	3,600	4,862	16,693	—
Purchases of reserves in place	6,546	13	—	6,559	—
Sales of reserves in place	(609)	—	—	(609)	—
Production	(6,477)	(13)	—	(6,490)	(25)
December 31, 2000	64,807	3,923	4,862	73,592	231
Revisions of previous estimates	25,140	(4,224)	(4,862)	16,054	(118)
Extensions, discoveries and other	24,843	1,173	7,771	33,787	—
Purchases of reserves in place	101	10,570	—	10,671	—
Production	(8,227)	(560)	—	(8,787)	(16)
December 31, 2001	106,664	10,882	7,771	125,317	97
Revisions of previous estimates	(32,823)	(1,798)	(5,660)	(40,281)	—
Extensions, discoveries and other	4,565	282	10,541	15,388	—
Purchases of reserves in place	—	362	—	362	—
Sales of reserves in place	(4,998)	(2,535)	—	(7,533)	(97)
Production	(6,928)	(1,053)	—	(7,981)	—
December 31, 2002	66,480	6,140	12,652	85,272	—
Proved developed reserves					
December 31, 2000	36,404	2,723	—	39,127	231
December 31, 2001	62,704	7,341	—	70,045	97
December 31, 2002	40,621	4,446	—	45,067	—

(1) Includes oil, condensate and natural gas liquids.
(2) Includes International operations in Brazil, Hungary and Indonesia.
(3) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries that were sold in 2002.
(4) Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner.

The significant changes to reserves, other than purchases, sales or production, are due to reservoir performance in existing fields and from drilling additional wells in existing fields. There have been no major discoveries or other events, favorable or adverse, that may be considered to have caused a significant change in the estimated proved reserves since December 31, 2002.

Results of operations from producing activities by fiscal year were as follows at December 31 (in millions):

	United States	Canada	Other Countries[1]	Worldwide
2002				
Net Revenues				
Sales to external customers	$ 241	$ 47	$ —	$ 288
Affiliated sales	886	20	—	906
Total	1,127	67	—	1,194
Production costs[2]	(163)	(18)	(1)	(182)
Depreciation, depletion and amortization	(421)	(28)	—	(449)
Ceiling test charges	—	(226)	(10)	(236)
Loss on sale of assets[3]	(702)	—	—	(702)
	(159)	(205)	(11)	(375)
Income tax benefit	58	83	4	145
Results of operations from producing activities	$ (101)	$(122)	$ (7)	$ (230)
2001				
Net Revenues				
Sales to external customers	$ 391	$ 45	$ —	$ 436
Affiliated sales	1,484	1	—	1,485
Total	1,875	46	—	1,921
Production costs[2]	(210)	(12)	—	(222)
Depreciation, depletion and amortization	(435)	(17)	—	(452)
Ceiling test charges	—	(87)	(28)	(115)
	1,230	(70)	(28)	1,132
Income tax (expense) benefit	(430)	25	(9)	(414)
Results of operations from producing activities	$ 800	$ (45)	$(37)	$ 718
2000				
Net Revenues				
Sales to external customers	$ 867	$ 6	$ —	$ 873
Affiliated sales	214	—	—	214
Total	1,081	6	—	1,087
Production costs[2]	(236)	(1)	—	(237)
Depreciation, depletion and amortization	(372)	(1)	—	(373)
	473	4	—	477
Income tax expense	(160)	(2)	—	(162)
Results of operations from producing activities	$ 313	$ 2	$ —	$ 315

(1) Includes international operations in Brazil, Hungary and Indonesia.

(2) Production costs include direct lifting costs (labor, repairs and maintenance materials and supplies) and the administrative costs of field offices, insurance and property and severance taxes.

(3) We recognized a loss of $702 million, or $452 million net of tax, on the sale of natural gas and oil properties in Utah. A loss was recognized on this sale because the reserves sold exceeded 25 percent of our total reserves and significantly altered the relationship between capitalized costs and proved reserves.

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves follows at December 31 (in millions):

	United States	Canada	Other Countries[(1)]	Worldwide	Natural Gas Systems[(2)]
2002					
Future cash inflows[(3)]	$ 8,625	$ 671	$ 542	$ 9,838	$ —
Future production costs	(1,418)	(127)	(124)	(1,669)	—
Future development costs	(1,022)	(16)	(133)	(1,171)	—
Future income tax expenses	(1,585)	(21)	(50)	(1,656)	—
Future net cash flows	4,600	507	235	5,342	—
10% annual discount for estimated timing of cash flows	(1,822)	(220)	(127)	(2,169)	—
Standardized measure of discounted future net cash flows	$ 2,778	$ 287	$ 108	$ 3,173	$ —
Standardized measure of discontinued future net cash flows, including effects of hedging activities	$ 2,718	$ 287	$ 108	$ 3,113	$ —
2001					
Future cash inflows[(4)]	$ 9,815	$ 641	$ 253	$10,709	$ 313
Future production costs	(1,691)	(196)	(51)	(1,938)	(34)
Future development costs	(1,391)	(83)	(73)	(1,547)	(30)
Future income tax expenses	(1,436)	(8)	(23)	(1,467)	(83)
Future net cash flows	5,297	354	106	5,757	166
10% annual discount for estimated timing of cash flows	(2,347)	(143)	(52)	(2,542)	(72)
Standardized measure of discounted future net cash flows	$ 2,950	$ 211	$ 54	$ 3,215	$ 94
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 3,361	$ 211	$ 54	$ 3,626	$ 94
2000					
Future cash inflows[(5)]	$27,535	$1,597	$ 397	$29,529	$ 474
Future production costs	(3,767)	(136)	(70)	(3,973)	(59)
Future development costs	(1,297)	(35)	(139)	(1,471)	(51)
Future income tax expenses	(7,014)	(599)	(60)	(7,673)	(116)
Future net cash flows	15,457	827	128	16,412	248
10% annual discount for estimated timing of cash flows	(6,522)	(469)	(109)	(7,100)	(89)
Standardized measure of discounted future net cash flows	$ 8,935	$ 358	$ 19	$ 9,312	$ 159
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 8,590	$ 358	$ 19	$ 8,967	$ 159

(1) Includes international operations in Brazil, Hungary and Indonesia.
(2) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries that were sold in 2002.
(3) Excludes $111 million of future cash outflows attributable to hedging activities.
(4) Excludes $684 million of future cash inflows attributable to hedging activities.
(5) Excludes $555 million of future cash outflows attributable to hedging activities.

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end market natural gas and oil prices. We may receive amounts different than the standardized measure of discounted cash flow for a number of reasons, including price changes and the effects of our hedging activities.

We do not rely upon the standardized measure when making investment and operating decisions. These decisions are based on various factors including probable and proved reserves, different price and cost assumptions, actual economic conditions, capital availability and corporate investment criteria.

The following are the principal sources of change in the standardized measure of discounted future net cash flows (in millions):

	Years Ended December 31,(1)				
	2002	2001		2000	
	Exploration and Production(2)	Exploration and Production(2)	Natural Gas Systems(3)	Exploration and Production(2)	Natural Gas Systems(3)
Sales and transfers of natural gas and oil produced net of production costs	$(1,011)	$(1,697)	$(255)	$(1,300)	$(52)
Net changes in prices and production costs	3,652	(8,160)	10	6,697	150
Extensions, discoveries and improved recovery, less related costs	568	766	—	3,586	—
Changes in estimated future development costs	(362)	(20)	13	—	—
Previously estimated development costs incurred during the period	258	337	—	83	—
Revisions of previous quantity estimates	(884)	(1,085)	39	(693)	34
Accretion of discount	387	1,308	23	194	4
Net change in income taxes	(237)	3,098	25	(3,337)	(42)
Purchases of reserves in place	13	222	—	1,292	—
Sales of reserves in place	(2,962)	—	—	(14)	—
Changes in production rates, timing and other	536	(866)	80	49	—
Net change	$ (42)	$(6,097)	$ (65)	$ 6,557	$ 94

(1) This disclosure reflects the change in standardized measure excluding the effects of hedging activities.
(2) Includes operations in the United States, Canada, Brazil, Hungary and Indonesia.
(3) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries that were sold in 2002.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholder of
El Paso CGP Company

In our opinion, the consolidated financial statements in the Index appearing under Item 15(a)(1) present fairly, in all material respects, the consolidated financial position of El Paso CGP Company and its subsidiaries (the "Company") at December 31, 2002 and 2001, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for each of the two years in the period ended December 31, 2002 listed in the index under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1, the Company adopted Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* and Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* on January 1, 2002; DIG Issue No. C-16, *Scope Exceptions: Applying the Normal Purchases and Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract* in the second quarter of 2002, and EITF Issue No. 02-3, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities, Consensus 1 and 2*; in the third and fourth quarter of 2002, respectively.

As discussed in Notes 1 and 11, the Company adopted Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities,* on January 1, 2001.

We also audited the adjustments described in Note 18 that were applied to restate the disclosures of 2000 segment information in the accompanying consolidated financial statements to give retroactive effect to the change in reportable segments. In our opinion, such adjustments are appropriate and have been properly applied to the prior period consolidated financial statements.

As discussed in Note 17, during 2001, the Company changed the measurement date used to account for pension and postretirement benefits other than pensions from December 31 to September 30.

/s/ PRICEWATERHOUSECOOPERS LLP

Houston, Texas
March 28, 2003

INDEPENDENT AUDITORS' REPORT

Board of Directors and Stockholder of
El Paso CGP Company
Houston, Texas

We have audited the consolidated statements of income, stockholders' equity, cash flows and comprehensive income of El Paso CGP Company (formerly The Coastal Corporation) and subsidiaries, for the year ended December 31, 2000. Our audit also included the financial statement schedule listed in the Index at Item 15(a)2. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the El Paso CGP Company's results of operations and cash flows for the year ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Houston, Texas
March 19, 2001
(March 28, 2003 as to the effects of reclassifications related to the adoption of net reporting for trading activities and discontinued operations as discussed in notes 1 and 9, respectively)

SCHEDULE II

EL PASO CGP COMPANY AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2002, 2001 and 2000
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses and Other	Charged to Other Accounts	Deductions	Balance at End of Period
2002					
Allowance for doubtful accounts	$ 36	$ 7	$ 4	$(10)[1]	$ 37
Legal reserves	81	10	13	(49)[2]	55
Environmental reserves	260	14	(95)[6]	(23)	156
Provision for refund	5	7	—	(8)	4
Planned major maintenance accrual	36	20	—	(16)	40
2001					
Allowance for doubtful accounts	$ 19	$ 23	$ —	$ (6)[1]	$ 36
Legal reserves	32	50[3]	—	(1)	81
Environmental reserves	28	242[3]	—	(10)	260
Provision for refund	—	5	—	—	5
Planned major maintenance accrual	51	(1)[4]	—	(14)	36
2000					
Allowance for doubtful accounts	$ 32	$ 3	$(14)	$ (2)[1]	$ 19
Legal reserves	48	(14)[5]	—	(2)	32
Environmental reserves	27	10	—	(9)	28
Provision for refund	8	2	—	(10)	—
Planned major maintenance accrual	34	33	—	(16)	51

(1) Primarily accounts written off.

(2) Payments for various litigation reserves.

(3) These amounts primarily relate to additional liabilities recorded in connection with changes in our estimates of these liabilities. See Note 5 for a further discussion of this change.

(4) During 2001, we accrued $23 million of reserves. In June, we leased our Corpus Christi refinery to Valero, and as a result we reversed $24 million of reserves.

(5) Includes reversal of $16 million of legal reserves due to a favorable resolution of natural gas price-related contingencies.

(6) In November 2002, we sold Coastal Mart Inc to an affiliate of El Paso Corporation which included environmental reserves of $95 million.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

PART III

Item 10, "Directors and Executive Officers of the Registrant;" Item 11, "Executive Compensation;" Item 12, "Security Ownership of Certain Beneficial Owners and Management;" and Item 13, "Certain Relationships and Related Transactions," have been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

ITEM 14. CONTROLS AND PROCEDURES

Evaluation of Controls and Procedures. Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (Disclosure Controls) and internal controls (Internal Controls) within 90 days of the filing date of this annual report pursuant to Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 (Exchange Act).

Definition of Disclosure Controls and Internal Controls. Disclosure Controls are our controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified under the Exchange Act. Disclosure Controls include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Internal Controls are procedures which are designed with the objective of providing reasonable assurance that (1) our transactions are property authorized; (2) our assets are safeguarded against unauthorized or improper use; and (3) our transactions are properly recorded and reported, all to permit the preparation of our financial statements in conformity with generally accepted accounting principles.

Limitations on the Effectiveness of Controls. El Paso CGP Company's management, including the principal executive officer and principal financial officer, does not expect that our Disclosure Controls and Internal Controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, control may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

No Significant Changes in Internal Controls. We have sought to determine whether there were any "significant deficiencies" or "material weaknesses" in El Paso CGP Company's Internal Controls, or whether the company had identified any acts of fraud involving personnel who have a significant role in El Paso CGP Company's Internal Controls. This information was important both for the controls evaluation generally and because the principal executive officer and principal financial officer are required to disclose that information to our Board's Audit Committee and our independent auditors and to report on related matters in this section of the Annual Report. The principal executive officer and principal financial officer note that, from the date of the controls evaluation to the date of this Annual Report, there have been no significant changes in Internal Controls or in other factors that could significantly affect Internal Controls, including any corrective actions with regard to significant deficiencies and material weaknesses.

Effectiveness of Disclosure Controls. Based on the controls evaluation, our principal executive officer and principal financial officer have concluded that, subject to the limitations discussed above, the Disclosure Controls are effective to ensure that material information relating to El Paso CGP Company's and its consolidated subsidiaries is made known to management, including the principal executive officer and principal financial officer, particularly during the period when our periodic reports are being prepared.

Officer Certification. The certifications from the principal executive officer and principal financial officer required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included herein, or as Exhibits to this Annual Report, as appropriate.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

(a) The following documents are filed as part of this report:

1. Financial statements.

Our consolidated financial statements are included in Part II, Item 8 of this report:

The following financial statements of our equity investments are included on the following pages of this report:

2. Financial statement schedules and supplementary information required to be submitted.

Schedules other than those listed above are omitted because they are not applicable.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

FINANCIAL STATEMENTS
WITH INDEPENDENT AUDITORS' REPORT
December 31, 2002

INDEPENDENT AUDITORS' REPORT

The Partners and Management Committee
Great Lakes Gas Transmission Limited Partnership:

We have audited the accompanying consolidated balance sheets of Great Lakes Gas Transmission Limited Partnership and subsidiary (Partnership) as of December 31, 2002 and 2001, and the related consolidated statements of income and partners' capital, and cash flows for each of the years in the three year period ended December 31, 2002. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Great Lakes Gas Transmission Limited Partnership and subsidiary as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America.

/s/ KPMG LLP

Detroit, Michigan
January 8, 2003

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

CONSOLIDATED STATEMENTS OF INCOME AND PARTNERS' CAPITAL

	Years Ended December 31,		
	2002	2001	2000
	(Thousands of Dollars)		
Transportation Revenues	$ 277,515	$ 276,872	$ 282,636
Operating Expenses			
Operation and Maintenance	37,075	32,662	39,807
Depreciation	56,916	56,640	60,705
Income Taxes Payable by Partners	45,400	39,950	39,518
Property and Other Taxes	14,393	28,828	29,322
	153,784	158,080	169,352
Operating Income	123,731	118,792	113,284
Other Income (Expense)			
Interest on Long Term Debt	(44,539)	(47,960)	(47,474)
Allowance for Funds Used During Construction	500	464	769
Other, Net	3,350	2,511	5,935
	(40,689)	(44,985)	(40,770)
Net Income	$ 83,042	$ 73,807	$ 72,514
Partners' Capital			
Balance at Beginning of Year	$ 443,640	$ 449,237	$ 604,838
Contributions by General Partners	25,432	21,226	19,290
Net Income	83,042	73,807	72,514
Current Income Taxes Payable by Partners Charged to Earnings	27,801	23,378	24,548
Distributions to Partners	(134,403)	(124,008)	(271,953)
Balance at End of Year	$ 445,512	$ 443,640	$ 449,237

The accompanying notes are an integral part of these statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2002	As of December 31, 2001
	(Thousands of Dollars)	
ASSETS		
Current Assets		
Cash and Temporary Cash Investments	$ 30,752	$ 40,320
Receivable from Limited Partner	—	1,922
Accounts Receivable	35,395	29,145
Materials and Supplies, at Average Cost	9,906	10,035
Regulatory Assets	515	566
Prepayments and Other	4,431	4,403
	80,999	86,391
Gas Utility Plant		
Property, Plant and Equipment	1,993,249	1,965,442
Less Accumulated Depreciation	822,763	772,832
	1,170,486	1,192,610
	$1,251,485	$1,279,001
LIABILITIES & PARTNERS' CAPITAL		
Current Liabilities		
Current Maturities of Long Term Debt	$ 24,000	$ 36,500
Accounts Payable	16,492	14,344
Payable to Limited Partner	562	—
Property and Other Taxes	26,764	27,895
Accrued Interest and Other	12,757	13,421
	80,575	92,160
Long Term Debt	497,500	532,250
Other Liabilities		
Amounts Equivalent to Deferred Income Taxes	224,298	206,057
Regulatory Liabilities	2,454	3,870
Other	1,146	1,024
	227,898	210,951
Partners' Capital	445,512	443,640
	$1,251,485	$1,279,001

The accompanying notes are an integral part of these statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2002	2001	2000
	(Thousands of dollars)		
Cash Flow Increase (Decrease) from:			
Operating Activities			
Net Income	$ 83,042	$ 73,807	$ 72,514
Adjustments to Reconcile Net Income to Operating Cash Flows:			
Depreciation	56,916	56,640	60,705
Amounts Equivalent to Deferred Income Taxes	18,241	12,918	15,411
Regulatory Assets	51	6,950	1,209
Regulatory Liabilities	(1,416)	(1,417)	(1,452)
Allowance for Funds Used During Construction	(500)	(464)	(769)
Changes in Current Assets and Liabilities:			
Accounts Receivable	(6,250)	6,166	(1,289)
Accounts Payable	2,148	(5,667)	(1,205)
Property and Other Taxes	(1,131)	(1,445)	(1,689)
Other	2,043	(9,630)	(52)
	153,144	137,858	143,383
Investment in Utility Plant	(34,292)	(31,574)	(33,372)
Financing Activities			
Issuance of Long Term Debt	—	—	100,000
Repayment of Long Term Debt	(47,250)	(26,500)	(17,800)
Contributions by Partners	25,432	21,226	19,290
Current Income Taxes Payable by Partners Charged to Earnings	27,801	23,378	24,548
Distributions to Partners	(134,403)	(124,008)	(271,953)
	(128,420)	(105,904)	(145,915)
Change in Cash and Cash Equivalents	(9,568)	380	(35,904)
Cash and Cash Equivalents:			
Beginning of Year	40,320	39,940	75,844
End of Year	$ 30,752	$ 40,320	$ 39,940
Supplemental Disclosure of Cash Flow Information			
Cash Paid During the Year for Interest			
(Net of Amounts Capitalized of $214, $206 and $249, Respectively)	$ 45,004	$ 48,197	$ 44,199

The accompanying notes are an integral part of these statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Management

Great Lakes Gas Transmission Limited Partnership (Partnership) is a Delaware limited partnership which owns and operates an interstate natural gas pipeline system. The Partnership transports natural gas for delivery to customers in the midwestern and northeastern United States and eastern Canada. Partnership ownership percentages are recalculated each year to reflect distributions and contributions. The partners, their parent companies, and partnership ownership percentages are as follows:

Partner (Parent Company)	Ownership % 2002	Ownership % 2001
General Partners:		
El Paso Great Lakes, Inc. (El Paso Corporation)	45.74	45.40
TransCanada GL, Inc. (TransCanada PipeLines Ltd.)	45.74	45.40
Limited Partner:		
Great Lakes Gas Transmission Company (TransCanada PipeLines Ltd. and El Paso Corporation)	8.52	9.20

The El Paso Corporation (El Paso) interests were formerly owned by The Coastal Corporation (Coastal), which merged into a subsidiary of El Paso on January 29, 2001.

The day-to-day operation of Partnership activities is the responsibility of Great Lakes Gas Transmissions Company (Company), which is reimbursed for its employee salaries, benefits and other expenses, pursuant to the Partnership's Operating Agreement with the Company.

2. Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of the Partnership and GLGT Aviation Company, a wholly owned subsidiary. GLGT Aviation Company owns a transport aircraft used principally for pipeline operations. Intercompany amounts have been eliminated.

For purposes of reporting cash flows, the Partnership considers all liquid investments with original maturities of three months or less to be cash equivalents.

The Partnership recognizes revenues from natural gas transportation in the period the service is provided.

Management of the Partnership has made estimates and assumptions relating to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities to prepare these financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ from those estimates.

Regulation

The Partnership is subject to the rules, regulations and accounting procedures of the Federal Energy Regulatory Commission (FERC). The Partnership's accounting policies reflect the effects of the ratemaking process in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. Regulatory assets and liabilities have been established and represent probable future revenue or expense which will be recovered from or refunded to customers. The regulatory assets and liabilities are primarily related to prior changes in federal income tax rates.

Accounts Receivable

Accounts Receivable are reported net of an allowance for doubtful accounts of $2,095,000 and $1,200,000 for 2002 and 2001, respectively. Late fees are recognized as income when earned.

Gas Utility Plant and Depreciation

Gas utility plant is stated at cost and includes certain administrative and general expenses, plus an allowance for funds used during construction. The cost of plant retired is charged to accumulated depreciation. Depreciation of gas utility plant is computed using the straight-line method. The Partnership's principal operating assets are depreciated at an annual rate of 2.75% for both 2002 and 2001 and 3.00% for 2000.

The allowance for funds used during construction represents the debt and equity costs of capital funds applicable to utility plant under construction, calculated in accordance with a uniform formula prescribed by the FERC. The rate used for both 2002 and 2001 was 10.36% and for 2000 was 10.95%.

Income Taxes

The Partnership's tariff includes an allowance for income taxes which the FERC requires the Partnership to record as if it were a corporation. The provisions for current and deferred income tax expense are recorded without regard to whether each partner can utilize its share of the Partnership's tax deductions. Income taxes are deducted in the Consolidated Statements of Income and the current portion of income taxes is returned to partners' capital. Recorded current income taxes are distributed to partners based on their ownership percentages.

Amounts equivalent to deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases at currently enacted income tax rates.

3. Affiliated Company Transactions

Affiliated company amounts included in the Partnership's consolidated financial statements, not otherwise disclosed, are as follows:

	2002	2001	2000
		(In thousands)	
Accounts receivable	$ 15,999	$ 15,936	$ 17,447
Transportation revenues:			
TransCanada PipeLines Ltd. and affiliates	163,442	176,818	185,912
El Paso Corporation and affiliates	24,875	25,716	—
The Coastal Corporation affiliates	—	—	28,981
Interest income	—	—	3,664

The majority of affiliated transportation revenues are provided under fixed price contracts with remaining terms ranging from 2 months to 10 years.

The Partnership reimburses the Company for salaries, benefits and other incurred expenses. Benefits include pension, thrift plan, and other post-retirement benefits. Operating expenses charged by the Company in 2002, 2001 and 2000 were $17,888,000, $13,671,000 and $21,147,000, respectively.

The Company accounts for pension benefits on an accrual basis. Effective with the merger of The Coastal Corporation and El Paso Corporation in 2001, the former pension plan was merged into the El Paso cash balance pension plan. The annual net pension credit was $5,400,000, $8,500,000 and $5,000,000 in 2002, 2001 and 2000, respectively.

The Company makes contributions for eligible employees of the Company to a voluntary defined contribution plan sponsored by one of the parent companies. The Company's contributions, which are based on matching employee contributions, amounted to $770,000, $832,000 and $980,000 in 2002, 2001 and 2000, respectively.

The Company accounts for other post-retirement benefits on an accrual basis. The annual expense was $236,000, $215,000 and $556,000 for 2002, 2001 and 2000, respectively. In addition, curtailment costs of approximately $695,000 were recorded in 2001 related to the conversion to the El Paso Corporation benefit plans, which changed future benefits for eligible employees.

4. Regulatory Matters

On October 26, 2000, the FERC issued an order approving the Partnership's filing of a Joint Stipulation and Agreement Regarding Rates which was subsequently reaffirmed on February 8, 2001, by its order denying rehearing. The settlement continues the Partnership's existing rates until October 31, 2005, and provides a decrease in the Partnership's depreciation rate from 3.00% to 2.75% for transmission plant effective January 1, 2001.

5. Debt

Senior Notes, unsecured, interest due semiannually, principal due as follows:

	2002	2001
	(In thousands)	
9.81% series, due 2002	$ —	$ 12,750
9.35% series, due 2002 to 2005	31,500	56,000
8.74% series, due 2002 to 2011	90,000	100,000
9.09% series, due 2012 to 2021	100,000	100,000
6.73% series, due 2009 to 2018	90,000	90,000
6.95% series, due 2019 to 2028	110,000	110,000
8.08% series, due 2021 to 2030	100,000	100,000
	521,500	568,750
Less current maturities	24,000	36,500
Total long term debt less current maturities	$497,500	$532,250

The aggregate estimated fair value of long term debt was $628,000,000 and $607,000,000 for 2002 and 2001, respectively. The fair value is determined using discounted cash flows based on the Partnership's estimated current interest rates for similar debt.

The aggregate annual required repayments of Senior Notes for each of the five years 2003 through 2007 are $24,000,000, $24,000,000, $13,500,000, $10,000,000 and $10,000,000, respectively.

Under the most restrictive covenants in the Senior Note Agreements, approximately $281,000,000 of partners' capital is restricted as to distributions as of December 31, 2002.

6. Income Taxes Payable by Partners

Income tax expense for the years ended December 31, 2002, 2001 and 2000 consists of:

	2002	2001	2000
		(In thousands)	
Current			
Federal	$26,612	$22,366	$23,496
State	1,189	1,012	1,052
	27,801	23,378	24,548
Deferred			
Federal	16,808	15,835	14,306
State	791	737	664
	17,599	16,572	14,970
	$45,400	$39,950	$39,518

Income tax expense differs from the statutory rate of 35% due to the amortization of excess deferred taxes along with the effects of state and local taxes. The Partnership is required to amortize excess deferred taxes which had previously been accumulated at tax rates in excess of current statutory rates. Such amortization reduced income tax expense by $900,000 for 2002, 2001 and 2000. As of December 31, 2002, the remaining unamortized balance is $1,475,000.

Amounts equivalent to deferred income taxes are principally comprised of temporary differences associated with excess tax depreciation on utility plant. As of December 31, 2002 and 2001, no valuation allowance is required. The deferred tax assets and deferred tax liabilities as of December 31, 2002 and 2001 are as follows:

	2002	2001
	(In thousands)	
Deferred tax assets	$ 5,110	$ 4,868
Deferred tax liabilities — utility plant	(214,526)	(197,927)
Deferred tax liabilities — other	(14,882)	(12,998)
Net deferred tax liability	$(224,298)	$(206,057)

7. Use Tax Refunds

In the first quarter of 2002, Great Lakes received a favorable decision from the Minnesota Supreme Court on use tax litigation and has collected refunds and related interest on litigated claims and pending claims for 1994 to 2001. The total amount received was $13.7 million. The refunds are reflected in Property and Other Taxes ($10.9 million) and the interest included in Other, Net ($2.8 million).

EL PASO CGP COMPANY

EXHIBIT LIST

December 31, 2002

Each exhibit identified below is filed as a part of this report. Exhibits not incorporated by reference to a prior filing are designated by an asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

Exhibit No.	Description
3.A	Amended and Restated Certificate of Incorporation dated January 31, 2001 (Exhibit 3.A to our 2000 Form 10-K).
*3.B	By-laws dated June 24, 2002.
10.A	$1,000,000,000 Amended and Restated 3-Year Revolving Credit and Competitive Advance Facility Agreement dated June 27, 2002, by and among El Paso EPNG, TGP, El Paso CGP, the several banks and other financial institutions from time to time parties thereto, and JPMorgan Chase Bank, as Administrative Agent, CAF Advance Agent and Issuing Bank, Citibank, N.A. and ABN Amro Bank N.V., as Co-Documentation Agents, and Bank of America, N.A., as Syndication Agent (Exhibit 10.B to our 2002 Second Quarter Form 10-Q).
*99.A	Certification of Chief Executive Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002. A signed original of this written statement required by sec. 906 has been provided to El Paso CGP Company and will be retained by El Paso CGP Company and furnished to the Securities and Exchange Commission or its staff upon request.
*99.B	Certification of Chief Financial Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002. A signed original of this written statement required by sec. 906 has been provided to El Paso CGP Company and will be retained by El Paso CGP Company and furnished to the Securities and Exchange Commission or its staff upon request.

(b) Reports on Form 8-K

January 28, 2003	Announced the sale of our petroleum terminals and tug & barge operations and provided pro-forma financials of El Paso CGP.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, El Paso CGP Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 31st day of March 2003.

EL PASO CGP COMPANY
Registrant

By: /s/ RONALD L. KUEHN, JR.
Ronald L. Kuehn, Jr.
Chairman of the Board and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of El Paso CGP Company and in the capacities and on the dates indicated:

Signature	Title	Date
By: /s/ RONALD L. KUEHN, JR. (Ronald L. Kuehn, Jr.)	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	March 31, 2003
By: /s/ H. BRENT AUSTIN (H. Brent Austin)	President, Chief Operating Officer and Director	March 31, 2003
By: /s/ D. DWIGHT SCOTT (D. Dwight Scott)	Executive Vice President and Chief Financial Officer and Director (Principal Financial Officer)	March 31, 2003
By: /s/ JEFFREY I. BEASON (Jeffrey I. Beason)	Senior Vice President and Controller (Principal Accounting Officer)	March 31, 2003

CERTIFICATION

I, Ronald L. Kuehn, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of El Paso CGP Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

/s/ RONALD L. KUEHN, JR.

Ronald L. Kuehn, Jr.
Chairman of the Board and
Chief Executive Officer
(Principal Executive Officer)
El Paso CGP Company

Date: March 31, 2003

CERTIFICATION

I, D. Dwight Scott, certify that:

1. I have reviewed this annual report on Form 10-K of El Paso CGP Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

/s/ D. DWIGHT SCOTT

D. Dwight Scott
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)
El Paso CGP Company

Date: March 31, 2003